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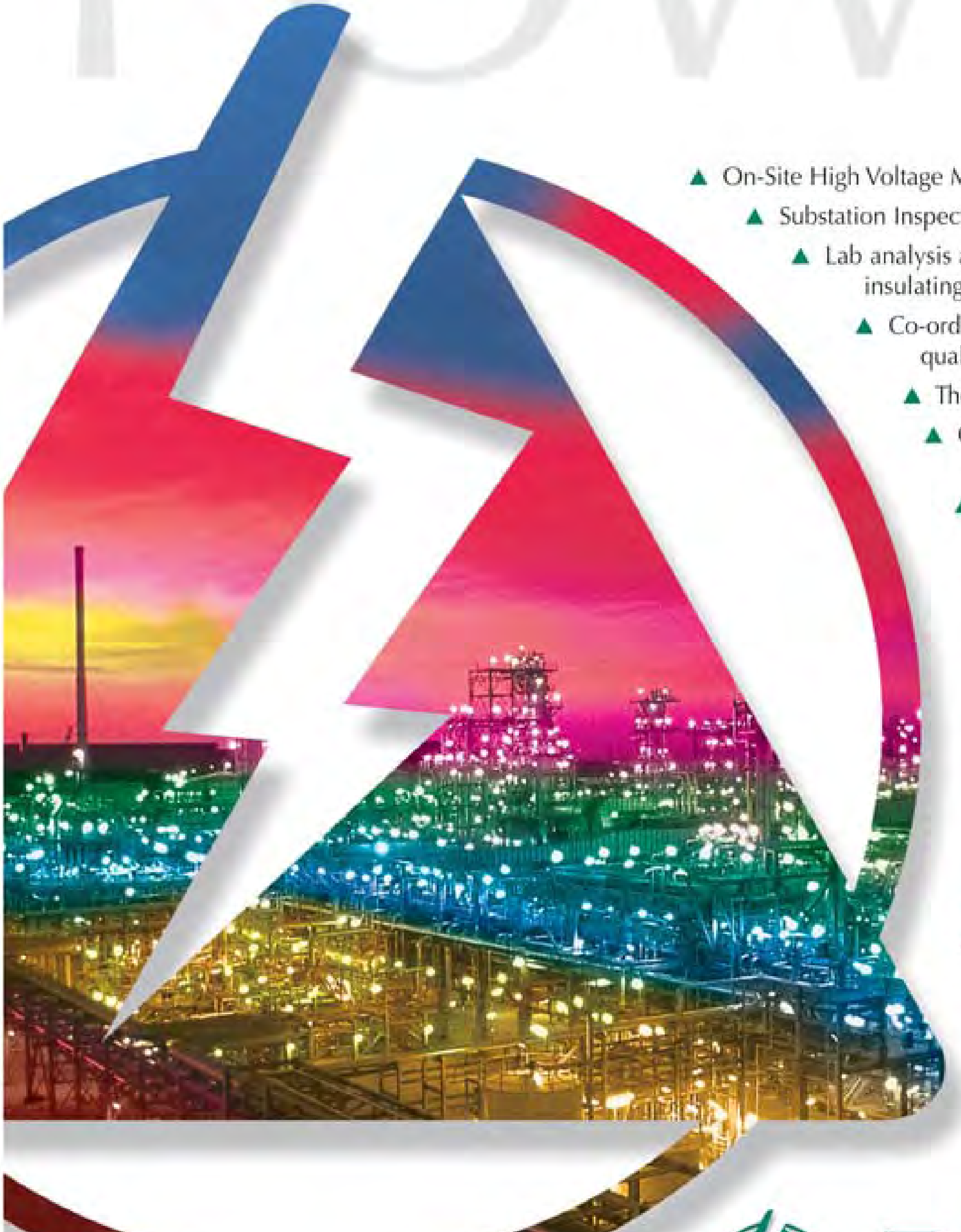

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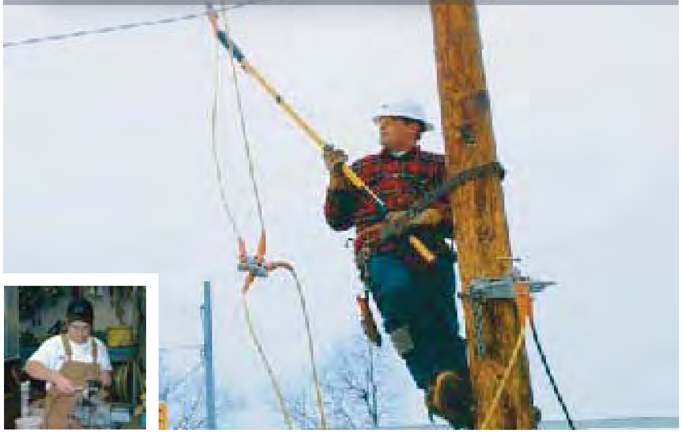

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THE ART & SCIENCE OF PROTECTIVE RELAYING - CURRENT TRANSFORMERS

C. Russell Mason, General Electric

Protective relays of the AC type are actuated by current and voltage supplied by current and voltage transformers. These transformers provide insulation against the high voltage of the power circuit, and also supply the relays with quantities proportional to those of the power circuit, but sufficiently reduced in magnitude so that the relays can be made relatively small and inexpensive.

The proper application of current and voltage transformers involves the consideration of several requirements, as follows: mechanical construction, type of insulation (dry or liquid), ratio in terms of primary and secondary currents or voltages, continuous thermal rating, short-time thermal and mechanical ratings, insulation class, impulse level, service conditions, accuracy, and connections. Application standards for most of these items are available. Most of them are self-evident and do not require further explanation. Our purpose here will be to concentrate on accuracy and connections because these directly affect the performance of protective relaying, and we shall assume that the other general requirements are fulfilled.

The accuracy requirements of different types of relaying equipment differ. Also, one application of a certain relaying equipment may have more rigid requirements than another application involving the same type of relaying equipment. Therefore, no general rules can be given for all applications. Technically, an entirely safe rule would be to use the most accurate transformers available, but few would follow the rule because it would not always be economically justifiable.

Therefore, it is necessary to be able to predict, with sufficient accuracy, how any particular relaying equipment will operate from any given type of current or voltage source. This requires that one know how to determine the inaccuracies of current and voltage transformers under different conditions, in order to determine what effect these inaccuracies will have on the performance of the relaying equipment.

Methods of calculation will be described using the data that are published by the manufacturers; these data are generally sufficient. A problem that cannot be solved by calculation using these data should be solved by actual test or should be referred to the manufacturer. This section is not intended as a text for a CT designer, but as a generally helpful reference for usual relay-application purposes.

The methods of connecting current and voltage transformers also are of interest in view of the different quantities that can be obtained from different combinations. Knowledge of the polarity of a current or voltage transformer and how to make use of this knowledge for making connections and predicting the results are required.

TYPES OF CURRENT TRANSFORMERS

All types of current transformeres are used for protective-relaying purposes. The bushing CT is almost invariably chosen for relaying in the higher-voltage circuits because it is less expensive than other types. It is not used in circuits below about 5 kv or in metal-clad equipment. The bushing type consists only of an annular-shaped core with a secondary winding; this transformer is built into equipment such as circuit breakers, power transformers, generators, or switchgear, the core being arranged to encircle an insulating bushing through which a power conductor passes.

Because the internal diameter of a bushing-CT core has to be large to accommodate the bushing, the mean length of the magnetic path is greater than in other CTs. To compensate for this, and also for the fact that there is only one primary turn, the cross section of the core is made larger. Because there is less saturation in a core of greater cross section, a bushing CT tends to be more accurate than other CTs at high multiples of the primary-current rating. At low currents, a bushing CT is generally less accurate because of its larger exciting current.

CALCULATION OF CT ACCURACY

Rarely, if ever, is it necessary to determine the phase-angle error of a CT used for relaying purposes. One reason for this is that the load on the secondary of a CT is generally of such highly lagging power factor that the secondary current is practically in phase with the exciting current, and hence the effect of the exciting current on the phase-angle accuracy is negligible. Furthermore, most relaying applications can tolerate what for metering purposes would be an intolerable phase-angle error. If the ratio error can be tolerated, the phase-angle error can be neglected. Consequently, phase-angle errors will not be discussed further. The technique for calculating the phase-angle error will be evident, once one learns how to calculate the ratio error.

Accuracy calculations need to be made only for three-phase- and single-phase-to-ground fault currents. If satisfactory results are thereby obtained, the accuracy will be satisfactory for phase-to-phase and two-phase-to-ground faults.

CURRENT-TRANSFORMER BURDEN

All CT accuracy considerations require knowledge of the CT burden. The external load applied to the secondary of a current transformer is called the “burden”. The burden is expressed preferably in terms of the impedance of the load and its resistance and reactance components. Formerly, the practice was to express the burden in terms of volt-amperes and power factor, the volt-amperes being what would be consumed in the burden impedance at rated secondary current (in other words, rated secondary current squared times the burden impedance). Thus, a burden of 0.5-ohm impedance may be expressed also as “12.5 volt-amperes at 5 amperes”, if we assume the usual 5-ampere secondary rating. The volt ampere terminology is no longer standard, but it needs defining because it will be found in the literature and in old data.

The term "burden" is applied not only to the total external load connected to the terminals of a current transformer but also to elements of that load. Manufacturers' publications give the burdens of individual relays, meters, etc., from which, together with the resistance of interconnecting leads, the total CT burden can be calculated.

The CT burden impedance decreases as the secondary current increases, because of saturation in the magnetic circuits of relays and other devices. Hence, a given burden may apply only for a particular value of secondary current. The old terminology of "volt-amperes at 5 amperes" is most confusing in this respect since it is not necessarily the actual voltamperes with 5 amperes flowing, but is what the volt-amperes would be at 5 amperes if there were no saturation. Manufacturers' publications give impedance data for several values of overcurrent for some relays for which such data are sometimes required.

Otherwise, data are provided only for one value of CT secondary current. If a publication does not clearly state for what value of current the burden applies, this information should be requested. Lacking such saturation data, one can obtain it easily by test. At high saturation, the impedance approaches the DC resistance. Neglecting the reduction in impedance with saturation makes it appear that a CT will have more inaccuracy than it actually will have. Of course, if such apparently greater inaccuracy can be tolerated, further refinements in calculation are unnecessary. However, in some applications neglecting the effect of saturation will provide overly optimistic results; consequently, it is safer always to take this effect into account.

It is usually sufficiently accurate to add series burden impedances arithmetically. The results will be slightly pessimistic, indicating slightly greater than actual CT ratio inaccuracy. But, if a given application is so borderline that vector addition of impedances is necessary to prove that the CTs will be suitable, such an application should be avoided.

If the impedance at pickup of a tapped overcurrent-relay coil is known for a given pickup tap, it can be estimated for pickup current for any other tap. The reactance of a tapped coil varies as the square of the coil turns, and the resistance varies approximately as the turns. At pickup, there is negligible saturation, and the resistance is small compared with the reactance. Therefore, it is usually sufficiently accurate to assume that the impedance varies as the square of the turns. The number of coil turns is inversely proportional to the pickup current, and therefore the impedance varies inversely approximately as the square of the pickup current.

Whether CTs are connected in wye or in delta, the burden impedances are always connected in wye. With wye-connected CTs the neutrals of the CTs and of the burdens are connected together, either directly or through a relay coil, except when a so-called "zerophase-sequence-current shunt" (to be described later) is used.

It is seldom correct simply to add the impedances of series burdens to get the total, whenever two or more CTs are connected in such a way that their currents may add or subtract in some common portion of the secondary circuit. Instead, one must calculate the sum of the voltage drops and rises in the external circuit from one CT secondary terminal to the other for assumed values of secondary currents flowing in the various branches of the external circuit. The effective CT burden impedance for each combination of assumed currents is the calculated CT terminal voltage divided by the assumed CT secondary current. This effective impedance is the one to use, and it may be larger or smaller than the actual impedance which would apply if no other CTs were supplying current to the circuit. If the primary of an auxiliary CT is to be connected into the secondary of a CT whose accuracy is being studied, one must know the impedance of the auxiliary CT viewed from its primary with its secondary short-circuited. To this value of impedance must be added the impedance of the auxiliary CT burden as viewed from the primary side of the auxiliary CT; to obtain this impedance, multiply the actual burden impedance by the square of the ratio of primary to secondary turns of the auxiliary CT. It will become evident that, with an auxiliary CT that steps up the magnitude of its current from primary to secondary, very high burden impedances, when viewed from the primary, may result.

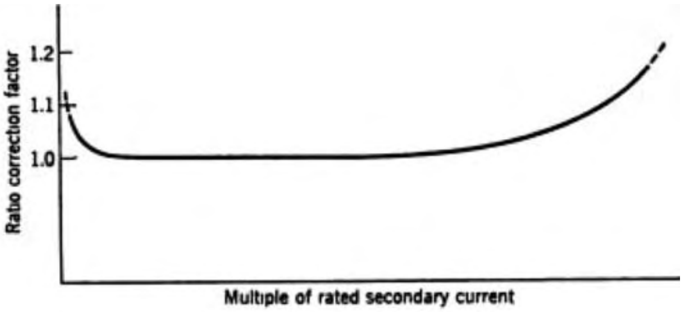


Fig. 1. Ratio-correction-factor curve of a current transformer.

RATIO-CORRECTION-FACTOR CURVES

The term "ratio-correction factor" is defined as "that factor by which the marked (or nameplate) ratio of a current transformer must be multiplied to obtain the true ratio."

The ratio errors of current transformers used for relaying are such that, for a given magnitude of primary current, the secondary current is less than the marked ratio would indicate; hence, the ratio-correction factor is greater than 1. A ratio-correction-factor curve is a curve of the ratio-correction factor plotted against multiples of rated primary or secondary current for a given constant burden, as in Fig. 1. Such curves give the most accurate results because the only errors involved in their use are the slight differences in accuracy between CTs having the same nameplate ratings, owing to manufacturers' tolerances. Usually, a family of such curves is provided for different typical values of burden.

To use ratio-correction-factor curves, one must calculate the CT burden for each value of secondary current for which one wants to know the CT accuracy. Owing to variation in burden with secondary current because of saturation, no single RCF curve will apply for all currents because these curves are plotted for constant burdens; instead, one must use the applicable curve, or interpolate between curves, for each different value of secondary current. In this way, one can calculate the primary currents for various assumed values of secondary current; or, for a given primary current, he can determine, by trial and error, what the secondary current will be.

The difference between the actual burden power factor and the power factor for which the RCF curves are drawn may be neglected because the difference in CT error will be negligible. Ratio-correction-factor curves are drawn for burden power factors approximately like those usually encountered in relay applications, and hence there is usually not much discrepancy. Any application should be avoided where successful relay operation depends on such small margins in CT accuracy that differences in burden power factor would be of any consequence.

Extrapolations should not be made beyond the secondary current or burden values for which the RCF curves are drawn, or else unreliable results will be obtained.

Ratio-correction-factor curves are considered standard application data and are furnished by the manufacturers for all types of current transformers.

CALCULATION OF CT ACCURACY USING A SECONDARY-EXCITATION CURVE

Figure 2 shows the equivalent circuit of a CT. The primary current is assumed to be transformed perfectly, with no ratio or phase-angle error, to a current IP/N, which is often called "the primary current referred to the secondary". Part of the current may be considered consumed in exciting the core, and this current (Ie) is called "the secondary excitation current." The remainder (Is) is the true secondary current. It will be evident that the secondary-excitation current is a function of the secondary-excitation voltage (Es) and the secondary-excitation impedance (Ze) The curve that relates Es and Ie is called "the secondary-excitation curve", an example of which is shown in Fig. 3. It will also be evident that the secondary current is a function of Es and the total impedance in the secondary circuit. This total impedance is composed of the effective resistance and the leakage reactance of the secondary winding and the impedance of the burden.

Figure 2 shows also the primary-winding impedance, but this impedance does not affect the ratio error. It affects only the magnitude of current that the power system can pass through the CT primary, and is of importance only in low-voltage circuits or when a CT is connected in the secondary of another CT.

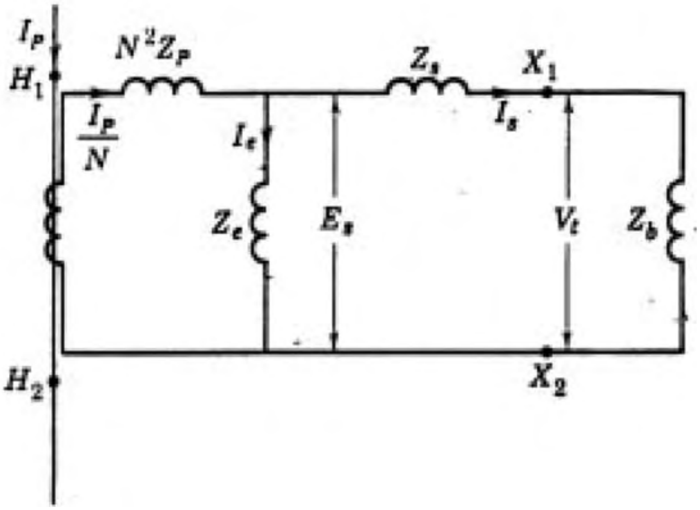


Fig. 2. Equivalent circuit of a current transformer. IP = primary current in rms amperes; N = ratio of secondary to primary turns; ZP = primary-winding impedance in ohms; Ie = secondary-excitation current in rms amperes; Ze = secondary-excitation impedance in ohms; Es = secondary-excitation voltage in rms volts; ZS = secondary-winding impedance in ohms; Is = secondary current in rms amperes; Vt = secondary terminal voltage in rms volts; Zb = burden impedance in ohms.

If the secondary-excitation curve and the impedance of the secondary winding are known, the ratio accuracy can be determined for any burden. It is only necessary to assume a magnitude of secondary current and to calculate the total voltage drop in the secondary winding and burden for this magnitude of current. This total voltage drop is equal numerically to Es. For this value of Es, the secondary-excitation curve will give Ie. Adding Ie to Is gives IP/N, and multiplying IP/N by N gives the value of primary current that will produce the assumed value of Is. The ratio-correction factor will be IP/NIs. By assuming several values of Is, and obtaining the ratio-correction factor for each, one can plot a ratio correction-factor curve. It will be noted that adding Is arithmetically to Ie may give a ratio-correction factor that is slightly higher than the actual value, but the refinement of vector addition is considered to be unnecessary.

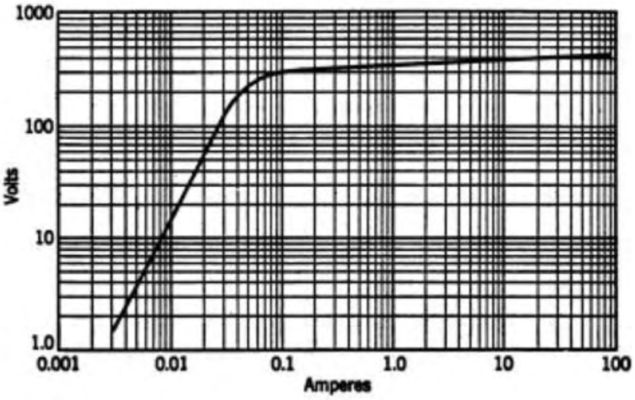


Fig. 3 Secondary-excitation characteristic. Frequency, 60; internal resistance, 1.08 ohms; secondary turns, 240.

The secondary resistance of a CT may be assumed to be the DC resistance if the effective value is not known. The secondary leakage reactance is not generally known except to CT designers; it is a variable quantity depending on the construction of the CT and on the degree of saturation of the CT core. Therefore, the secondary-excitation-curve method of accuracy determination does not lend itself to general use except for bushing-type, or other, CTs with completely distributed secondary windings, for which the secondary leakage reactance is so small that it may be assumed to be zero. In this respect, one should realize that, even though the total secondary winding is completely distributed, tapped portions of this winding may not be completely distributed; to ignore the secondary leakage reactance may introduce significant errors if an undistributed tapped portion is used.

The secondary-excitation-curve method is intended only for current magnitudes or burdens for which the calculated ratio error is approximately 10% or less. When the ratio error appreciably exceeds this value, the waveform of the secondary-excitation current — and hence of the secondary current — begins to be distorted, owing to saturation of the CT core. This will produce unreliable results if the calculations are made assuming sinusoidal waves, the degree of unreliability increasing as the current magnitude increases.

Even though one could calculate accurately the magnitude and wave shape of the secondary current, he would still have the problem of deciding how a particular relay would respond to such a current. Under such circumstances, the safest procedure is to resort to a test.

Secondary-excitation data for bushing CTs are provided by manufacturers. Occasionally, however, it is desirable to be able to obtain such data by test. This can be done accurately enough for all practical purposes merely by open-circuiting the primary circuit, applying AC voltage of the proper frequency to the secondary, and measuring the current that flows into the secondary. The voltage should preferably be measured by a rectifier-type voltmeter. The curve of rms terminal voltage versus rms secondary current is approximately the secondary-excitation curve for the test frequency. The actual excitation voltage for such a test is the terminal voltage minus the voltage drop in the secondary resistance and leakage reactance, but this voltage drop is negligible compared with the terminal voltage until the excitation current becomes large, when the GT core begins to saturate. If a bushing CT with a completely distributed secondary winding is involved, the secondary-winding voltage drop will be due practically only to resistance, and corrections in excitation voltage for this drop can be made easily. In this way, sufficiently accurate data can be obtained up to a point somewhat beyond the knee of the secondary-excitation curve, which is usually all that is required. This method has the advantage of providing the data with the CT mounted in its accustomed place.

Secondary-excitation data for a given number of secondary turns can be made to apply to a different number of turns on the same CT by expressing the secondary-excitation voltages in “volts” and the corresponding secondary-excitation currents in “ampere turns.” When secondary-excitation data are plotted in terms of volts-per-turn and ampere-turns, a single curve will apply to any number of turns.

The secondary-winding impedance can be found by test, but it is usually impractical to do so except in the laboratory. Briefly, it involves energizing the primary and secondary windings with equal and opposite ampere-turns, approximately equal to rated values, and measuring the voltage drop across the secondary winding. This voltage divided by the secondary current is called the “unsaturated secondary-winding impedance”. If we know the secondary-winding resistance, the unsaturated secondary leakage reactance can be calculated. If a bushing CT has secondary leakage flux because of an undistributed secondary winding, the CT should be tested in an enclosure of magnetic material that is the same as its pocket in the circuit breaker or transformer, or else most unreliable results will be obtained.

The most practical way to obtain the secondary leakage reactance may sometimes be to make an overcurrent ratio test, power-system current being used to get good wave form, with the CT in place, and with its secondary short-circuited through a moderate burden.

The only difficulty of this method is that some means is necessary to measure the primary current accurately. Then, from the data obtained, and by using the secondary-excitation curve obtained as previously described, the secondary leakage reactance can be calculated.

Such a calculation should be accurately made, taking into account the vector relations of the exciting and secondary currents and adding the secondary and burden resistance and reactance vectorially.

ASA ACCURACY CLASSIFICATION

The ASA accuracy classification for current transformers used for relaying purposes provides a measure of a CT’s accuracy. This method of classification assumes that the CT is supplying 20 times its rated secondary current to its burden, and the CT is classified on the basis of the maximum rms value of voltage that it can maintain at its secondary terminals without its ratio error exceeding a specified amount.

Standard ASA accuracy classifications are as shown. The letter “H” stands for “high internal secondary impedance”, which is a characteristic of CTs having concentrated secondary windings. The letter “L” stands for “low internal secondary impedance”, which is a characteristic of bushing-type CTs having completely distributed secondary windings or of window type having two to four secondary coils with low secondary leakage reactance.

The number before the letter is the maximum specified ratio error in percent (= 100|RCF — 1|), and the number after the letter is the maximum specified secondary terminal voltage at which the specified ratio error may exist, for a secondary current of 20 times rated. For a 5-ampere secondary, which is the usual rating, dividing the maximum specified voltage by 100 amperes (20 x 5 amperes) gives the maximum specified burden impedance through which the CT will pass 100 amperes with no more than the specified ratio error.

l0H10	l0L10
10H20	10L20
l0H50	l0L50
l0H100	l0L100
l0H200	l0L200
l0H400	l0L400
l0H800	l0L800
2.5H10	2.5L10
2.5H20	2.5L20
2.5H50	2.5L50
2.5H100	2.5L100
2.5H200	2.5L200
2.5H400	2.5L400
2.5H800	2.5L800

At secondary currents from 20 to 5 times rated, the H class of transformer will accommodate increasingly higher burden impedances than at 20 times rated without exceeding the specified maximum ratio error, so long as the product of the secondary current times the burden impedance does not exceed the specified maximum voltage at 20 times rated. This characteristic is the deciding factor when there is a question whether a given CT should be classified as “H” or as “L”. At secondary currents from rated to 5 times rated, the maximum permissible burden impedance at 5 times rated (calculated as before) must not be exceeded if the maximum specified ratio error is not to be exceeded.

At secondary currents from rated to 20 times rated, the L class of transformer may accommodate no more than the maximum specified burden impedance at 20 times rated without exceeding the maximum specified ratio error. This assumes that the secondary leakage reactance is negligible.

The reason for the foregoing differences in the permissible burden impedances at currents below 20 times rated is that in the H class of transformer, having the higher secondary winding impedance, the voltage drop in the secondary winding decreases with reduction in secondary current more rapidly than the secondary-excitation voltage decreases with the reduction in the allowable amount of exciting current for the specified ratio error. This fact will be better understood if one will calculate permissible burden impedances at reduced currents, using the secondary-excitation method.

For the same voltage and error classifications, the H transformer is better than the L for currents up to 20 times rated.

In some cases, the ASA accuracy classification will give very conservative results in that the actual accuracy of a CT may be nearly twice as good as the classification would indicate. This is particularly true in older CTs where no design changes were made to make them conform strictly to standard ASA classifications. In such cases, a CT that can actually maintain a terminal voltage well above a certain standard classification value, but not quite as high as the next higher standard value, has to be classified at the lower value. Also, some CTs can maintain terminal voltages in excess of 800 volts, but because there is no higher standard voltage rating, they must be classified “800”.

The principal utility of the ASA accuracy classification is for specification purposes, to provide an indication of CT quality. The higher the number after the letter H or L, the better is the CT. However, a published ASA accuracy classification applies only if the full secondary winding is used; it does not apply to any portion of a secondary winding, as in tapped bushing-CT windings. It is perhaps obvious that with fewer secondary turns, the output voltage will be less. A bushing CT that is superior when its full secondary winding is used may be inferior when a tapped portion of its winding is used if the partial winding has higher leakage reactance, because the turns are not well distributed around the full periphery of the core. In other words, the ASA accuracy classification for the full winding is not necessarily a measure of relative accuracy if the full secondary winding is not used.

If a bushing CT has completely distributed tap windings, the ASA accuracy classification for any tapped portion can be derived from the classification for the total winding by multiplying the maximum specified voltage by the ratio of the turns. For example, assume that a given 1200/5 bushing CT with 240 secondary turns is classified as 10L400; if a 120-turn completely distributed tap is used, the applicable classification is 10L200, etc. This assumes that the CT is not actually better than its classification.

Strictly speaking, the ASA accuracy classification is for a burden having a specified power factor. However, for practical purposes, the burden power factor may be ignored.

If the information obtainable from the ASA accuracy classification indicates that the CT is suitable for the application involved, no further calculations are necessary. However, if the CT appears to be unsuitable, a more accurate study should be made before the CT is rejected.

SERIES CONNECTION OF LOW-RATIO BUSHING CTÕS

It will probably be evident from the foregoing that a low-ratio bushing CT, having 10 to 20 secondary turns, has rather poor accuracy at high currents. And yet, occasionally, such CTs cannot be avoided, as for example, where a high-voltage, low-current circuit or power transformer winding is involved where rated full-load current is only, say, 50 amperes.

Then, two bushing CTs per phase are sometimes used with their secondaries connected in series. This halves the burden on each CT, as compared with the use of one CT alone, without changing the over-all ratio. And, consequently, the secondary-excitation voltage is halved, and the secondary-excitation current is considerably reduced with a resulting large improvement in accuracy. Such an arrangement may require voltage protectors to hold down the secondary voltage should a fault occur between the primaries of the two CTs.

THE TRANSIENT OR STEADY-STATE ERRORS OF SATURATED CTS

To calculate first the transient or steady-state output of saturated CTs, and then to calculate at all accurately the response of protective relays to the distorted wave form of the CT output, is a most formidable problem. With perhaps one exception, there is little in the literature that is very helpful in this respect.

Fortunately, one can get along quite well without being able to make such calculations.

With the help of calculating devices, comprehensive studies have been made that provide general guiding principles for applying relays so that they will perform properly even though the CT output is affected by saturation. And relaying equipment has been devised that can be properly adjusted on the basis of very simple calculations.

We are occasionally concerned lest a CT be too accurate when extremely high primary short-circuit currents flow! Even though the CT itself may be properly applied, the secondary current may be high enough to cause thermal or mechanical damage to some element in the secondary circuit before the short-circuit current can be interrupted. One should not assume that saturation of a CT core will limit the magnitude of the secondary current to a safe value. At very high primary currents, the air-core coupling between primary and secondary of wound-type CTs will cause much more secondary current to flow than one might suspect. It is recommended that, if the short-time thermal or mechanical limit of some element of the secondary circuit would be exceeded should the CT maintain its nameplate ratio, the CT manufacturer should be consulted. Where there is such possibility, damage can be prevented by the addition of a small amount of series resistance to the existing CT burden.

OVERVOLTAGE IN SATURATED CT SECONDARIES

Although the rms magnitude of voltage induced in a CT secondary is limited by core saturation, very high voltage peaks can occur. Such high voltages are possible if the CT burden impedance is high, and if the primary current is many times the CTs continuous rating. The peak voltage occurs when the rate-of-change of core flux is highest, which is approximately when the flux is passing through zero. The maximum flux density that may be reached does not affect the magnitude of the peak voltage. Therefore, the magnitude of the peak voltage is practically independent of the CT characteristics other than the nameplate ratio.

One series of tests on bushing CTs produced peak voltages whose magnitudes could be expressed empirically as follows:

$e = 3.5ZI\ 0.53$

where e = peak voltage in volts.

Z = unsaturated magnitude of CT burden impedance in ohms.

I = primary current divided by the CTs nameplate ratio. (Or, in other words, the rms magnitude of the secondary current if the ratio-correction factor were 1.)

The value of Z should include the unsaturated magnetizing impedance of any idle CTs that may be in parallel with the useful burden. If a tap on the secondary winding is being used, as with a bushing CT, the peak voltage across the full winding will be the calculated value for the tap multiplied by the ratio of the turns on the full winding to the turns on the tapped portion being used; in other words, the CT will step up the voltage as an autotransformer. Because it is the practice to ground one side of the secondary winding, the voltage that is induced in the secondary will be impressed on the insulation to ground.

The standard switchgear high potential test to ground is 1500 volts rms, or 2121 volts peak; and the standard CT test voltage is 2475 volts rms or 3500 volts peak. The lower of these two should not be exceeded.

Harmfully high secondary voltages may occur in the CT secondary circuit of generator differential-relaying equipment when the generator kva rating is low but when very high short-circuit kva can be supplied by the system to a short circuit at the generator's terminals. Here, the magnitude of the primary current on the system side of the generator windings may be many times the CT rating. These CTs will try to supply very high secondary currents to the operating coils of the generator differential relay, the unsaturated impedance of which may be quite high. The resulting high peak voltages could break down the insulation of the CTs, the secondary wiring, or the differential relays, and thereby prevent the differential relays from operating to trip the generator breakers.

Such harmfully high peak voltages are not apt to occur for this reason with other than motor or generator differential-relaying equipments because the CT burdens of other equipment are not usually so high. But, wherever high voltage is possible, it can be limited to safe values by overvoltage protectors.

Another possible cause of overvoltage is the switching of a capacitor bank when it is very close to another energized capacitor bank.

The primary current of a CT in the circuit of a capacitor bank being energized or deenergized will contain transient high-frequency currents. With high-frequency primary and secondary currents, a CT burden reactance, which at normal frequency is moderately low, becomes very high, thereby contributing to CT saturation and high peak voltages across the secondary. Overvoltage protectors may be required to limit such voltages to safe values.

It is recommended that the CT manufacturer be consulted whenever there appears to be a need for overvoltage protectors. The protector characteristics must be coordinated with the requirements of a particular application to (1) limit the peak voltage to safe values, (2) not interfere with the proper functioning of the protective-relaying equipment energized from the CT's, and (3) withstand the total amount of energy that the protector will have to absorb.

PROXIMITY EFFECTS

Large currents flowing in a conductor close to a current transformer may greatly affect its accuracy. A designer of compact equipment, such as metal-enclosed switchgear, should guard against this effect. If one has all the necessary data, it is a reasonably simple matter to calculate the necessary spacings to avoid excessive error.

POLARITY AND CONNECTIONS

The relative polarities of CT primary and secondary terminals are identified either by painted polarity marks or by the symbols "H1" and "H2" for the primary terminals and "X1" and "X2" for the secondary terminals. The convention is that, when primary current enters the H1 terminal, secondary current leaves the X1 terminal, as shown by the arrows in Fig. 4. Or, when current enters the H2 terminal, it leaves the X2 terminal.

When paint is used, the terminals corresponding to H1 and X1 are identified. Standard practice is to show connection diagrams merely by squares, as in Fig. 5.

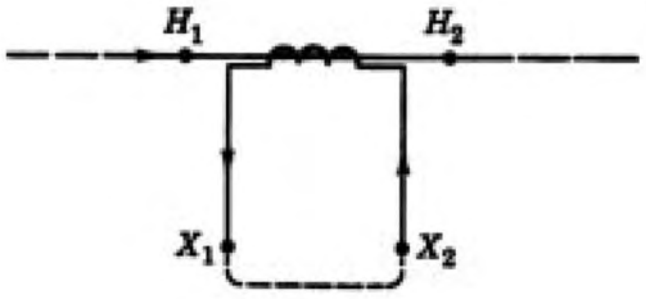


Fig. 4. The polarity of current trans the corresponding terminals in formers.

Since A/C current is continually reversing its direction, one might well ask what the significance is of polarity marking. Its significance is in showing the direction of current flow relative to another current or to a voltage, as well as to aid in making the proper connections. If CTs were not interconnected, or if the current from one CT did not have to cooperate with a current from another CT, or with a voltage from a voltage source, to produce some desired result such as torque in a relay, there would be no need for polarity marks.

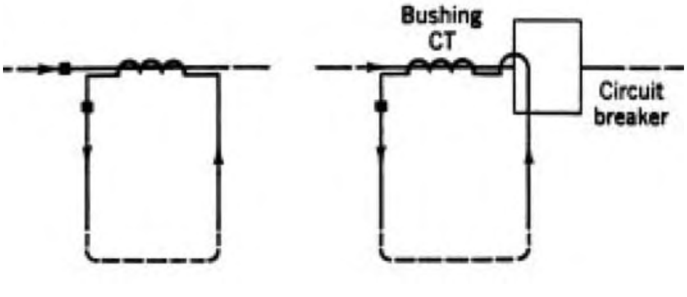


Fig. 5. Convention for showing polarity on diagrams.

CTs are connected in wye or in delta, as the occasion requires. Figure 6 shows a wye connection with phase and ground relays. The currents Ia, Ib, and Ic are the vector currents, and the CT ratio is assumed to be 1/1 to simplify the mathematics. Vectorially, the primary and secondary currents are in phase, neglecting phase-angle errors in the CTs.

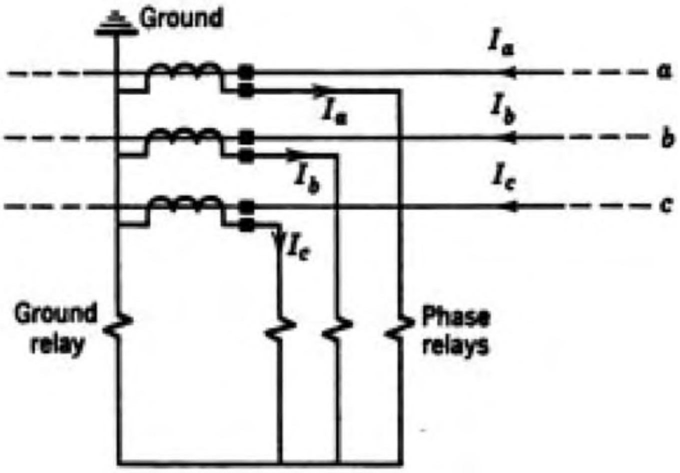


Fig. 6. Wye connection of current transformers.

The symmetrical-component method of analysis is a powerful tool, not only for use in calculating the power-system currents and voltages for unbalanced faults but also for analyzing the response of protective relays. In terms of phase-sequence components of the power-system currents, the output of wye-connected CT's is as follows:

$$I_a = I_{a1} + I_{a2} + I_{a0}$$

$$I_b = I_{b1} + I_{b2} + I_{b0} = a^2 I_{a1} + a I_{a2} + I_{a0}$$

$$I_c = I_{c1} + I_{c2} + I_{c0} = a I_{a1} + a^2 I_{a2} + I_{a0}$$

$$I_a + I_b + I_c = I_{a0} + I_{b0} + I_{c0} = 3I_{a0} = 3I_{b0} = 3I_{c0}$$

where 1, 2, and 0 designate the positive-, negative-, and zero-phase-sequence components, respectively, and where “a” and “a2” are operators that rotate a quantity counterclockwise 120° and 240°, respectively.

DELTA CONNECTION

With delta-connected CTs, two connections are possible, as shown in Fig. 7. In terms of the phase-sequence components, Ia, Ib, and Ic are the same as for the wye-connected CTs.

The output currents of the delta connections of Fig. 7 are, therefore:

Connection A.

$$\begin{aligned} I_a - I_b &= (I_{a1} - I_{b1}) + (I_{a2} - I_{b2}) \\ &= (1 - a^2) I_{a1} + (1 - a) I_{a2} \\ &= (\tfrac{3}{2} + j\sqrt{3}/2)\, I_{a1} + (\tfrac{3}{2} - j\sqrt{3}/2)\, I_{a2} \end{aligned}$$

$$\begin{aligned} I_b - I_c &= (1 - a^2)\, I_{b1} + (1 - a)\, I_{b2} \\ &= a^2 (1 - a^2)\, I_{a1} + a\,(1 - a)\, I_{a2} \\ &= (a^2 - a)\, I_{a1} + (a - a^2)\, I_{a2} \\ &= -j\sqrt{3}\, I_{a1} + j\sqrt{3}\, I_{a2} \end{aligned}$$

$$\begin{aligned} I_c - I_a &= (1 - a^2)\, I_{c1} + (1 - a)\, I_{c2} \\ &= a(1 - a^2)\, I_{a1} + a^2 (1 - a)\, I_{a2} \\ &= (a - 1)\, I_{a1} + (a^2 - 1)\, I_{a2} \\ &= (-\tfrac{3}{2} + j\sqrt{3/2})\, I_{a1} + (-\tfrac{3}{2} - j\sqrt{3/2})\, I_{a2} \end{aligned}$$

Connection B.

$$\begin{aligned} I_a - I_c &= -(I_c - I_a) \\ &= (\tfrac{3}{2} - j\sqrt{3/2}\,) I_{a1} + (\tfrac{3}{2} + j\sqrt{3/2}\,)\, I_{a2} \end{aligned}$$

$$\begin{aligned} I_b - I_a &= -(I_a - I_b) \\ &= (-\tfrac{3}{2} - j\sqrt{3/2}\,) I_{a1} + (-\tfrac{3}{2} + j\sqrt{3/2}\,)\, I_{a2} \end{aligned}$$

$$\begin{aligned} I_c - I_b &= -(I_b - I_c) \\ &= j\sqrt{3}\, I_{a1} - j\sqrt{3}\, I_{a2} \end{aligned}$$

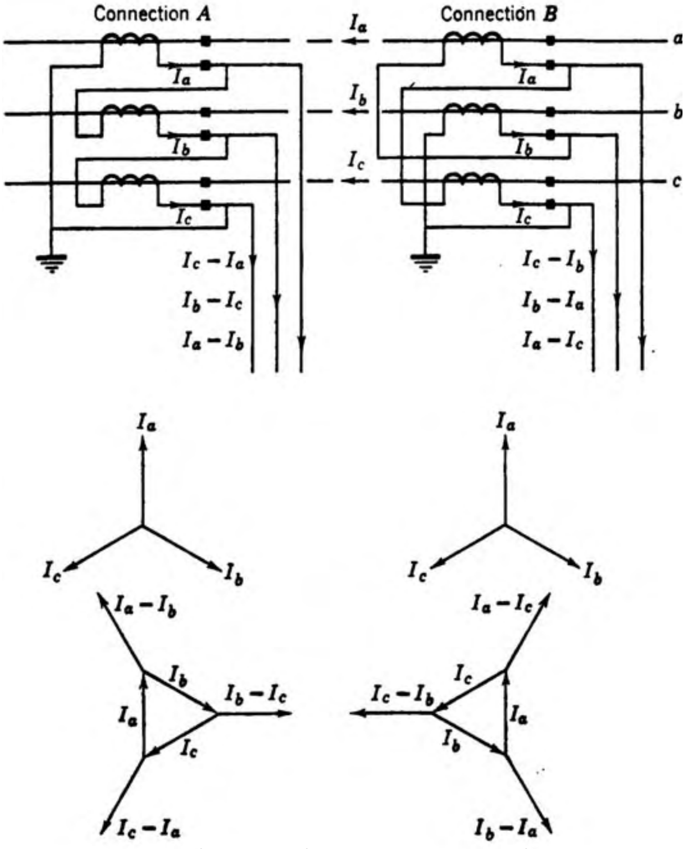


Fig. 7. Delta connections of current transformers and vector diagrams for balanced three-phase currents.

It will be noted that the zero-phase-sequence components are not present in the output circuits; they merely circulate in the delta connection. It will also be noted that connection

B is merely the reverse of connection A.

For three-phase faults, only positive-phase-sequence components are present. The output currents of connection A become:

$$I_a - I_b = (\frac{3}{2} + j\sqrt{3}/2)\ I_{a1}$$

$$I_b - I_c = -j\sqrt{3}\ I_{a1}$$

$$I_c - I_a = (-\frac{3}{2} + j\sqrt{3}/2)\ I_{a1}$$

For a phase-b-to-phase-c fault, if we assume the same distribution of positive- and negative-phase-sequence currents (which is permissible if we assume that the negative-phase-sequence impedances equal the positive-phase-sequence impedances), Ia2 = — Ia1, and the output currents of connection A become:

$$I_a - I_b = j\sqrt{3}\ I_{a1}$$

$$I_b - I_c = -j2\sqrt{3}\ I_{a1}$$

$$I_c - I_a = j\sqrt{3}\ I_{a1}$$

For a phase-a-to-ground fault, if we again assume the same distribution of positive- and negative-phase-sequence currents, Ia2 = Ia1, and the output currents of connection A become:

$$I_a - I_b = 3I_{a1}$$

$$I_b - I_c = 0$$

$$I_c - I_a = -\ 3I_{a1}$$

The currents for a two-phase-to-ground fault between phases b and c can be obtained in a similar manner if one knows the relation between the impedances in the negative- and zero-phase-sequence networks. It is felt, however, that the foregoing examples are sufficient to illustrate the technique involved. The assumptions that were made as to the distribution of the currents are generally sufficiently accurate, but they are not a necessary part of the technique; in any actual case, one would know the true distribution and also any angular differences that might exist, and these could be entered in the fundamental equations.

The output currents from wye-connected CTs can be handled in a similar manner.

THE ZERO-PHASE-SEQUENCE-CURRENT SHUNT

Figure 8 shows how three auxiliary CTs can be connected to shunt zero-phase-sequence currents away from relays in the secondary of wye-connected CTs. Other forms of such a shunt exist, but the one shown has the advantage that the ratio of the auxiliary CTs is not important so long as all three are alike. Such a shunt is useful in a differential circuit where the main CTs must be wye-connected but where zero-phase-sequence currents must be kept from the phase relays. Another use is to prevent misoperation of single-phase directional relays during ground faults under certain conditions. These will be discussed more fully later.

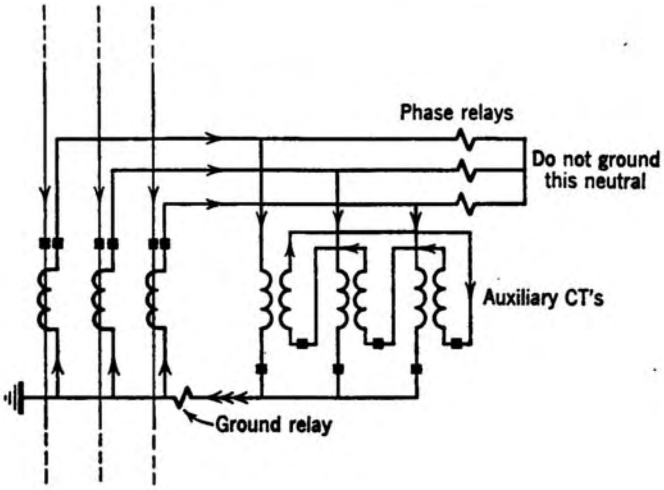


Fig. 8. A zero-phase-sequence-current shunt. Arrows show flow of zero-phase-sequence current.

PROBLEMS

1. What is the ASA accuracy classification for the full winding of the bushing CT whose secondary-excitation characteristic and secondary resistance are given on Fig. 3?

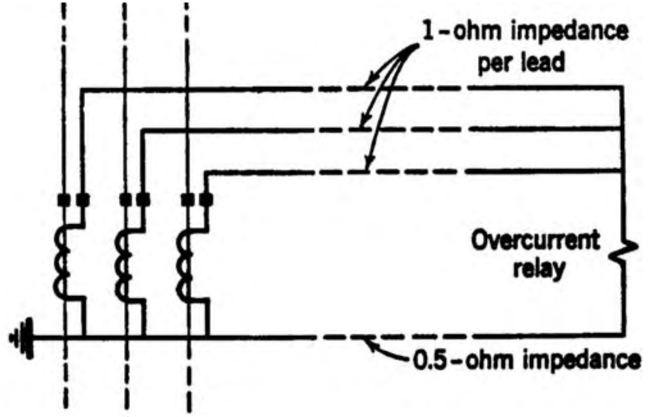


Fig. 9. Illustration for Problem 2.

2. For the overcurrent relay connected as shown in Fig. 9, determine the value of pickup current that will provide relay operation at the lowest possible value of primary current in one phase.

If the overcurrent relay has a pickup of 15 amperes, its coil impedance at 1.5 amperes is 2.4 ohms. Assume that the impedance at pickup current varies inversely as the square of pickup current, and that relays of any desired pickup are available to you.

A GUIDE TO TRANSFORMER DC RESISTANCE MEASUREMENTS

Bruce Hembroff, CEFT, Manitoba Hydro Additions and Editing by Matz Ohlen and Peter Werelius, Megger

1 INTRODUCTION

Winding resistance measurements in transformers are of fundamental importance for the following purposes:

- Calculations of the I2R component of conductor losses;
- Calculation of winding temperature at the end of a temperature test cycle;
- As a diagnostic tool for assessing possible damage in the field.

Transformers are subject to vibration. Problems or faults occur due to poor design, assembly, handing, poor environments, overloading or poor maintenance. Measuring the resistance of the windings assures that the connections are correct and the resistance measurements indicate that there are no severe mismatches or opens. Many transformers have taps built into them. These taps allow ratio to be increased or decreased by fractions of a percent. Any of the ratio changes involve a mechanical movement of a contact from one position to another. These tap changes should also be checked during a winding resistance test.

Regardless of the configuration, either star or delta, the measurements are normally made phase to phase and comparisons are made to determine if the readings are comparable. If all readings are within one percent of each other, then they are acceptable. Keep in mind that the purpose of the test is to check for gross differences between the windings and for opens in the connections. The tests are not made to duplicate the readings of the manufactured device which was tested in the factory under controlled conditions and perhaps at other temperatures.

This application note is focusing on using winding resistance measurements for diagnostic purposes.

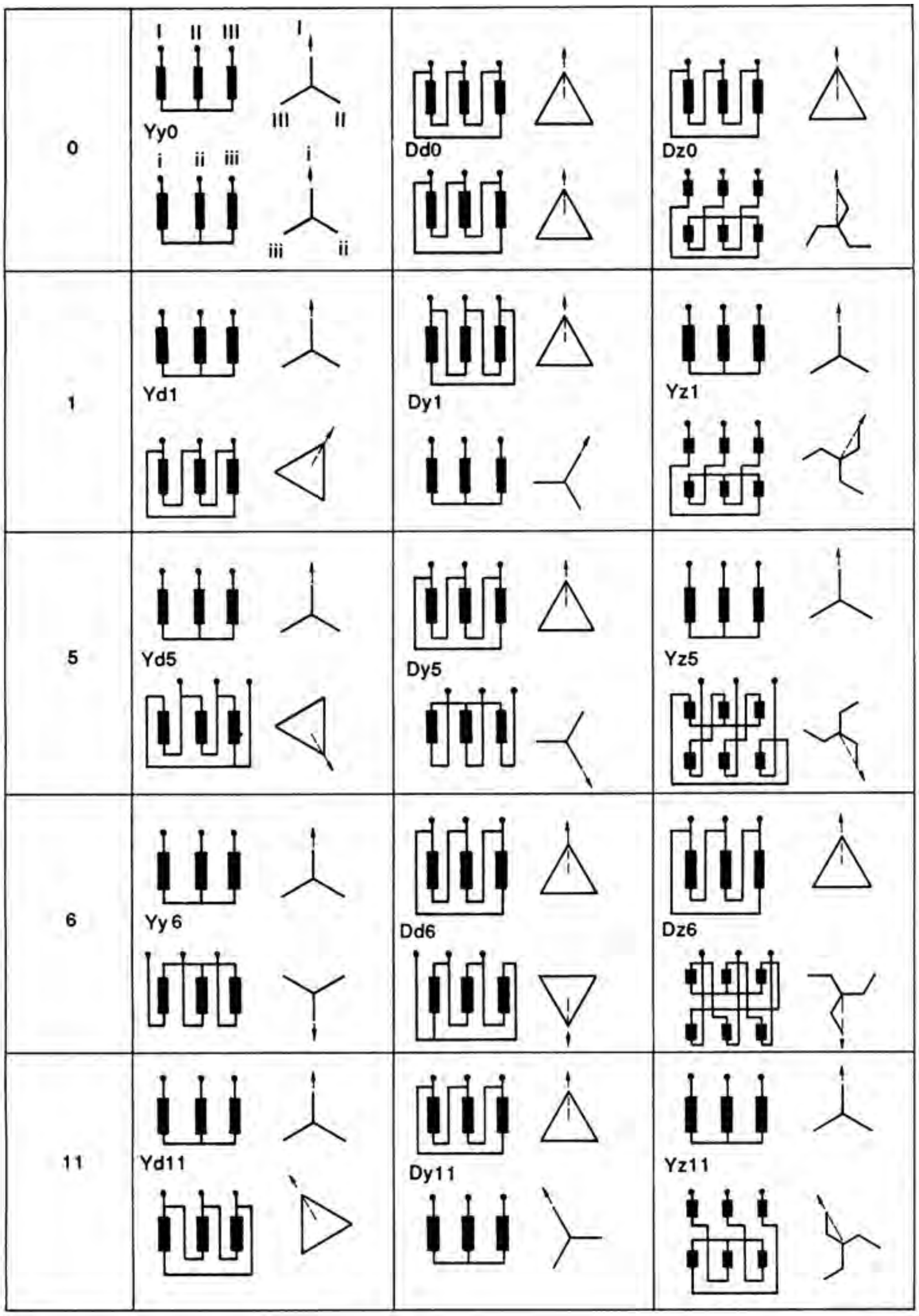


Figure 1. Common 3-phase Transformer Connections

IEC 265/93

2 TRANSFORMER DC RESISTANCE MEASUREMENTS

2.1 AT INSTALLATION

Risk of damage is significant whenever a transformer is moved. This is inherent to the typical transformer design and modes of transportation employed. Damage can also occur during unloading and assembly. The damage will often involve a current carrying component such as the LTC, RA switch or a connector. Damage to such components may result in a change to the DC resistance measured through them. Hence, it is recommended that the DC resistance be measured on all on-load and off-load taps prior to energizing.

If the transformer is new, the resistance test also serves as a verification of the manufacturer's work.

Installation measurements should be filed for future reference.

2.2 AT ROUTINE (SCHEDULED) TRANSFORMER MAINTENANCE

Routine maintenance is performed to verify operating integrity and to assure reliability. Tests are performed to detect incipient problems. What kind of problems will the resistance test detect?

2.2.1 RATIO ADJUSTING SWITCH (RATIO ADJUSTING OFF-LOAD TAP CHANGER)

Contact pressure is usually obtained through the use of springs. In time, metal fatigue will result in lower contact pressure. Oxygen and fault gases (if they exist) will attack the contact surfaces.

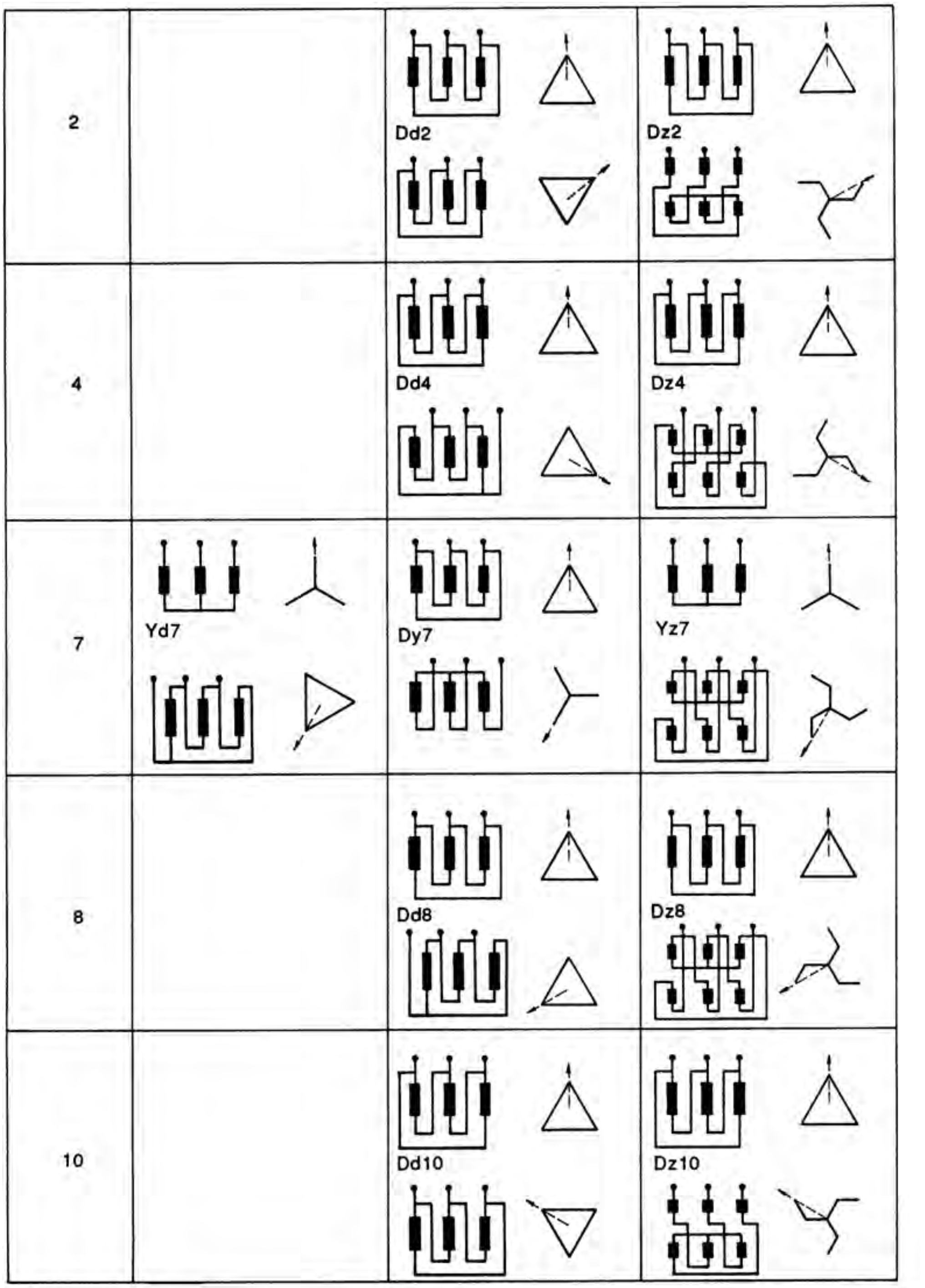
Additionally, mechanical damage resulting in poor contact pressure is not uncommon. (E.g. A misaligned switch handle linkage may result in switch damage when operated). Such problems will affect the DC resistance measured through the RA switch and may be detected.

2.2.2 LOAD TAP CHANGER

The LTC contains the majority of the contacts and connections in the transformer. It is one of few non-static devices in the transformer and is required to transfer load current several thousand times a year. Hence, it demands special consideration during routine maintenance.

In addition to detecting problems associated with high resistance contacts and connectors, WINDAX-125 Winding Resistance Meter will also detect open circuits (drop-out test). LTCs transfer load current and are designed for make-before-break, they are NOT designed to interrupt load current. An open circuit would likely result in catastrophic failure. On installation and after maintenance it is certainly prudent to verify operating integrity by checking for open circuits. LTC maintenance often involves considerable disassembly and the test will provide confidence in the reassembly.

It is recommended DC resistance measurements be made on all on-load and off- load taps to detect problems and verify operating integrity of the RA switch and LTC.



IEC 266/93

Figure 2. Alternative 3-phase Transformer Connections

2.3 AT UNSCHEDULED MAINTENANCE/TROUBLESHOOTING

Unscheduled maintenance generally occurs following a system event. The objectives of unscheduled maintenance are:

- To detect damage to the transformer;
- To determine if it is safe to re-energize;
- To determine if corrective action is necessary;
- To establish priority of corrective action.

Many transformer faults or problems will cause a change in the DC resistance measured from the bushings (shorted turns, open turns, poor joints or contacts). Hence, the information derived from the resistance test is very useful in analyzing faults or problems complimenting information derived from other diagnostic tests such as FRA, DRA (power factor), DGA and other measurements. The winding resistance test is particularly useful in isolating the location of a fault or problem and assessing the severity of the damage.

2.4 AT INTERNAL TRANSFORMER INSPECTIONS

Internal inspections are expensive due primarily to the cost of oil processing. When such opportunities do present themselves the inspection should be planned and thorough. Prior to dumping the oil, all possible diagnostic tests including the resistance test should be performed.

3 TEST EQUIPMENT

Prior to modern digital electronic equipment, the Kelvin Bridge was used. Batteries, switches, galvanometers, ammeters and slidewire adjustments were used to obtain resistance measurements.

Current regulators were constructed and inserted between the battery and the bridge. Input voltage to the regulator of 12 volts DC from an automobile storage battery provided output currents variable in steps which matched the maximum current rating of the bridge on the ranges most used on transformers. The current regulator increased both speed and accuracy of the bridge readings. The approximate 11 volt availability was used to speed up the initial current buildup and tapered off to about 5 volts just before the selected current was reached and regulation started. When the regulation began, the current was essentially constant in spite of the inductance of the windings and fluctuation of the battery voltage or lead resistance.

The testing times have been greatly reduced using modern microprocessor based test equipment.

Direct readings are available from digital meters with automatic indications telling when a good measurement is available. On some testers like the Pax WINDAX, two measurement channels are available allowing two resistance measurements at the same time.

4 SAFETY CONSIDERATIONS

While performing winding resistance tests, hazardous voltages could appear on the terminals of the transformer under test and/or the test equipment if appropriate safety precautions are not observed.

There are two sources to consider:

- AC induction from surrounding energized conductors; and
- The DC test current.

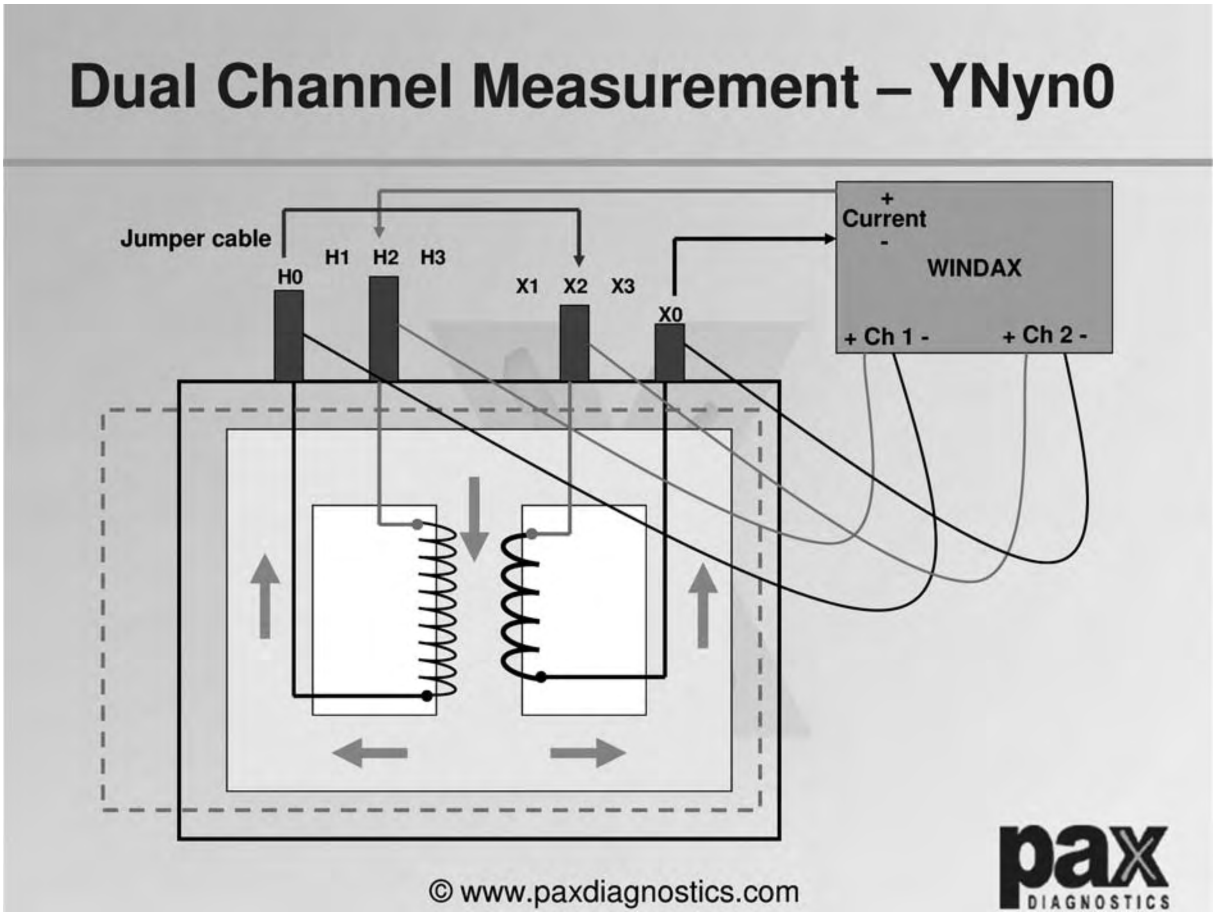


Figure 3. Measuring two windings simultaneously

4.1 AC INDUCTION

When a transformer is located in an AC switch yard in close proximity to energized conductors, it is quite probable an electrostatic charge would be induced onto a floating winding. This hazard can be eliminated by simply tying all windings to ground. However, to perform a winding resistance test only one terminal of any winding can be tied to ground. Grounding a second terminal will short that winding, making it impossible to measure the resistance of the winding. Two grounds on the winding under test would probably result in measuring the resistance of the ground loop. Two grounds on a winding which is not under test will create a closed loop inductor. Because all windings of a transformer are magnetically coupled, the DC test current will continually circulate within the closed loop inductor (the shorted winding). The instrument display would probably not stabilize, and accurate measurements would not be possible.

It does not matter which terminal is grounded, as long there is only one terminal of each winding tied to ground. When test leads are moved to subsequent phases or windings on the transformer, it is not necessary to move the ground connections. Ensure the winding is grounded prior to connecting the current and potential test leads, and when disconnecting leads remove the ground last.

4.2 DC TEST CURRENT

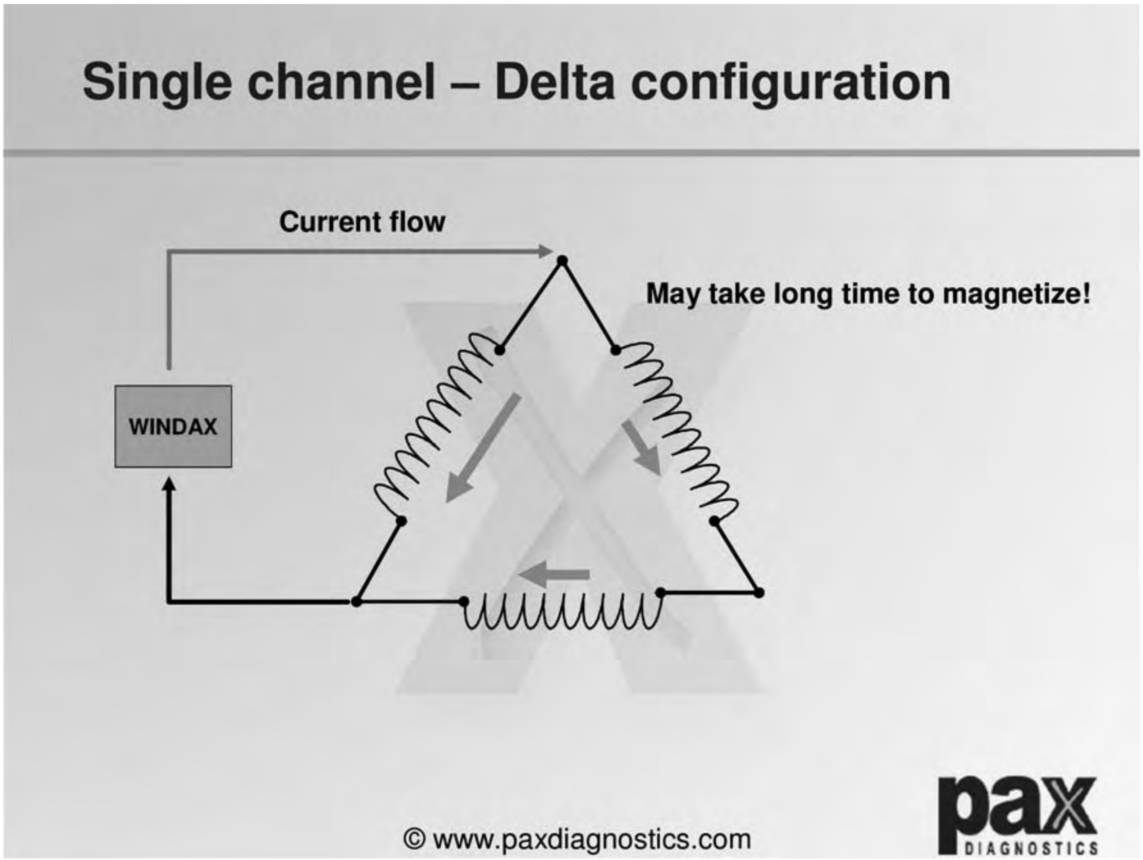
Should the test circuit become open while DC current is flowing, hazardous voltages (possibly resulting in flash over) will occur. Care must be taken to ensure the test circuit does not accidentally become open:

- Ensure the test leads are securely attached to the winding's terminals;
- Do not operate any instrument control which would open the measured circuit while DC current is flowing. Discharge the winding first;
- Do not disconnect any test leads while DC current is flowing. Ensure the winding is discharged first;
- When terminating the test, wait until the discharge indicator on WINDAX goes off before removing the current leads. When testing larger transformers, it may take 30 seconds or more to discharge the winding. If a longer time (30 seconds plus) is required to charge a winding when the current is initiated, a corresponding longer time will be required to discharge the winding.

4.3 SUMMARY OF SAFETY PRECAUTIONS

- Ensure all transformer windings and the test instrument chassis are grounded prior to connecting the test leads.
- Take appropriate precautions to ensure the test circuit is not opened while DC (test) current is flowing.

Failure to take appropriate precautions can result in hazardous potentials which could be harmful to both personnel and test equipment. It should be noted that transformer windings are essentially large inductors. The higher the voltage and the larger the (MVA) capacity, the higher the induction and hence the potential hazard.



Single channel – Delta configuration

May take long time to magnetize!

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Figure 4. Closed delta winding

5 SELECTING THE PROPER CURRENT RANGE

Transformer manufacturers typically recommend that the current output selected should not exceed about 10% of the rated winding current. This could cause erroneous readings due to heating of the winding (e.g. A transformer rated 1500 kVA, 1 ph: the rated current of the 33 kV winding is 45 amps; therefore the test current should not exceed 4.5 A. Do not select more than 4 A current output on WINDAX.)

Always choose the highest current output possible for the expected resistance value. Typical ranges are 0.1-10 % of rated winding current.

6 MEASUREMENTS

Wait until the display has stabilized prior to recording resistance values. Generally, readings on a star-configured transformer should stabilize in 10-30 seconds. However, the time required for readings to stabilize will vary, based on the rating of the transformer, the winding configuration, output voltage of the test instrument and the current output selected. On large transformers with high inductance windings, it could take a few minutes for readings to stabilize.

For large transformers with delta configuration, magnetization and getting stable readings can take significantly longer time, sometimes as long as 30-60 minutes (see Figure 4). If the readings don't stabilize within the maximum measurement time, check leads, connections and instrument. It may be necessary to reduce the test current and inject current on HV and LV windings simultaneously (recommended!), see sections 7.3 and 11, table 1.

• Record measurements as read. Do not correct for temperature. (When using the WINDAX PC SW, automatic re-calculation to normalized temperature can be done without changing the original test record). Do not calculate individual winding values for delta connected transformers.

• Record DC test current selected.

• Record unit of measure (ohms or milli-ohms).

• Review test data. Investigate and explain all discrepancies.

As a general rule, the first measurement made is repeated at the end of the test. Consistent first and last readings give credibility to all measurements. Whenever an unexpected measurement is obtained, the test method and procedure is questioned. If the measurement can be repeated, the doubt is removed. In situations where time is of concern, the repeat measurement can be omitted if all measurements are consistent.

Always check the winding schematic on the nameplate, and trace the current path(s) through the windings. The nameplate vector representation may be misleading. Also, check the location of grounds on the windings and ensure the grounds do not shunt the DC test current.

When a winding has both an RA switch (ratio adjusting off-load tap changer) and an LTC (load tapchanger) take measurements as follows:

• With the LTC on neutral measure resistance on all off-load taps.

• With the RA switch on nominal/rated tap measure resistance on all on-load taps.

6.1 RA SWITCH MEASUREMENTS

The recommended procedure for testing RA switches is as follows:

• Prior to moving the RA switch measure the resistance on the as found tap. Note: This measurement is particularly useful when investigating problems.

• Exercise the switch by operating it a half dozen times through full range. This will remove surface oxidization. See “Interpretation of Measurements - Confusion Factors”.

• Measure and record the resistance on all off-load taps.

• Set the RA switch to the as left tap and take one final measurement to ensure good contact. Do not move the RA switch after this final measurement has been made.

6.2 LTC MEASUREMENTS

As found measurements are performed for diagnostic purposes in both routine and non-routine situations. As left measurements are performed to verify operating integrity following work on the LTC. The resistance test on a transformer with an LTC is time consuming; hence the value of the as found test in each particular situation should be evaluated. Consider maintenance history and design. Certainly, if the proposed work involves an internal inspection (main tank) or a problem is suspected, the as found test should be performed.

Prior to taking as left measurements, exercise the LTC. Operating the LTC through its full range of taps two to six times should remove the surface oxidation.

When testing windings with LTCs, use the tap-changer setup on WINDAX to ensure that the measurement value for each tap is stored separately. The current generator is on throughout the test sequence while changing from tap to tap. With respect to the number of consecutive tests to perform, SW operation and data storage is recommended. However WINDAX can perform TC testing stand-alone.

Measure the resistance for first tap. Operate TC. Measure resistance for second tap, resistance value and current ripple for the previous tap change is stored. Operate TCS. Measure resistance for third tap etc.

Should the LTC open the circuit and cause current interruption, WINDAX will automatically stop and go into its discharge cycle indicated by the discharge LED. This gives the operator a clear indication by a panel light of a possible fault within the tap changer. Such transformers should not be returned to service as catastrophic failure would be possible.

7 CONNECTIONS

7.1 GENERAL

Prior to connecting the instrument leads to the transformer all transformer windings must be grounded. See Safety Considerations. Make connections in the following order:

1. Ensure winding terminals are not shorted together and tie to ground (the transformer tank) one terminal only of each transformer winding (i.e. both the winding to be tested as well as those not being tested). Note: It does not matter which terminal is grounded (a line terminal or neutral) as long as only one terminal on each winding is grounded. There is no need to move the ground as the test progresses to measuring subsequent phases or windings.

2. Ensure the instrument's power switch is in the OFF position and connect it to the mains supply. Note: The instruments chassis is grounded through the supply cable to the station service. (On occasion it has not been possible to stabilize the display when the instrument's chassis ground was not connected to the same ground point as the winding (i.e., the transformer tank). This problem is most likely to occur when the station service ground is not bonded to the transformer tank and is

easily remedied by connecting a jumper between the instrument chassis and the transformer tank.

3. Connect the current and potential leads to the instrument.

4. Connect the current and potential leads to the transformer winding. The potential leads must be connected between the current leads. Do not clip the potential leads to the current leads. Observe polarity.

5. Upon completion of the test, ensure the winding is discharged before disconnecting any test leads. Remove the ground from the transformer winding last. Caution: Do not open the test circuit in any way (i.e. disconnecting test leads, or operating the current selector switch) while DC current is flowing. Hazardous voltages (probably resulting in flash-over) will occur.

7.2 WYE WINDINGS

Refer to Figures 1-3 and Table 1. Measuring two windings simultaneously is possible if a suitable common test current can be selected. Take resistance measurements with the indicated connections.

Connecting the test equipment as per Figure 3 is the preferred method because it allows the operator to measure two phases simultaneously. Compared to measuring each phase individually, there is a significant time saving particularly when measuring a winding with an LTC. Alternately, if the instrument will not energize both windings simultaneously, measure one winding at a time.

If time is of concern, the last test set up, which is a repeat of the first, may be omitted if all measurements are consistent when comparing one phase to the next or to previous tests.

Table 1. Transformer Connection Schemes for measuring two windings simultaneously

IEC Vector Group	Transformer Configuration						
	High-Voltage Winding (H)			Low Voltage Winding (X)			
Dd0	**Delta**			**Delta**			
Test #	Current Connections			Meas ch 1		Meas ch 2	
	+ Current	Jumper	- Current	+	-	+	-
1	H1	H3-X1	X3	H1	H3	X1	X3
2	H2	H1-X2	X1	H2	H1	X2	X1
3	H3	H2-X3	X2	H3	H2	X3	X2
IEC Vector Group	Transformer Configuration						
	High-Voltage Winding (H)			Low Voltage Winding (X)			
Dyn7	**Delta**			**Y with neutral**			
Test #	Current Connections			Meas ch 1		Meas ch 2	
	+ Current	Jumper	- Current	+	-	+	-
1	H1	H3-X0	X1	H1	H3	X0	X1
2	H2	H1-X0	X2	H2	H1	X0	X2
3	H3	H2-X0	X3	H3	H2	X0	X3
IEC Vector Group	Transformer Configuration						
	High-Voltage Winding (H)			Low Voltage Winding (X)			
Dyn1	**Delta**			**Y with neutral**			
Test #	Current Connections			Meas ch 1		Meas ch 2	
	+ Current	Jumper	- Current	+	-	+	-
1	H1	H3-X1	X0	H1	H3	X1	X0
2	H2	H1-X2	X0	H2	H1	X2	X0
3	H3	H2-X3	X0	H3	H2	X3	X0
IEC Vector Group	Transformer Configuration						
	High-Voltage Winding (H)			Low Voltage Winding (X)			
YNyn0	**Y with neutral**			**Y with neutral**			
Test #	Current Connections			Meas ch 1		Meas ch 2	
	+ Current	Jumper	- Current	+	-	+	-
1	H1	H0-X1	X0	H1	H0	X1	X0
2	H2	H0-X2	X0	H2	H0	X2	X0
3	H3	H0-X3	X0	H3	H0	X3	X0
IEC Vector Group	Transformer Configuration						
	High-Voltage Winding (H)			Low Voltage Winding (X)			
Ynd1	**Y with neutral**			**Delta**			
Test #	Current Connections			Meas ch 1		Meas ch 2	
	+ Current	Jumper	- Current	+	-	+	-
1	H1	H0-X1	X2	H1	H0	X1	X2
2	H2	H0-X2	X3	H2	H0	X2	X3
3	H3	H0-X3	X1	H3	H0	X3	X1

Table 1. Transformer Connection Schemes for measuring two windings simultaneously (continued)

IEC Vector Group	Transformer Configuration						
	High-Voltage Winding (H)			Low Voltage Winding (X)			
Dy1	**Delta**			**Y without neutral**			
Test #	Current Connections			Meas ch 1		Meas ch 2	
	+ Current	Jumper	- Current	+	-	+	-
1	H1	H3-X1	X2	H1	H3	X3	X2
2	H2	H1-X2	X3	H2	H1	X1	X3
3	H3	H2-X3	X1	H3	H2	X2	X1
IEC Vector Group	Transformer Configuration						
	High-Voltage Winding (H)			Low Voltage Winding (X)			
YNd7	**Y with neutral**			**Delta**			
Test #	Current Connections			Meas ch 1		Meas ch 2	
	+ Current	Jumper	- Current	+	-	+	-
1	H1	H0-X2	X1	H1	H0	X2	X1
2	H2	H0-X3	X2	H2	H0	X3	X2
3	H3	H0-X1	X3	H3	H0	X1	X3
IEC Vector Group	Transformer Configuration						
	High-Voltage Winding (H)			Low Voltage Winding (X)			
Dyn5	**Delta**			**Y with neutral**			
Test #	Current Connections			Meas ch 1		Meas ch 2	
	+ Current	Jumper	- Current	+	-	+	-
1	H1	H2-X0	X1	H1	H2	X0	X1
2	H2	H3-X0	X2	H2	H3	X0	X2
3	H3	H1-X0	X3	H3	H1	X0	X3
IEC Vector Group	Transformer Configuration						
	High-Voltage Winding (H)			Low Voltage Winding (X)			
Dy11	**Delta**			**Y without neutral**			
Test #	Current Connections			Meas ch 1		Meas ch 2	
	+ Current	Jumper	- Current	+	-	+	-
1	H1	H2-X1	X3	H1	H2	X1	X3
2	H2	H3-X2	X1	H2	H3	X2	X1
3	H3	H1-X3	X2	H3	H1	X3	X2
IEC Vector Group	Transformer Configuration						
	High-Voltage Winding (H)			Low Voltage Winding (X)			
Dyn11	**Delta**			**Y with neutral**			
Test #	Current Connections			Meas ch 1		Meas ch 2	
	+ Current	Jumper	- Current	+	-	+	-
1	H1	H2-X1	X0	H1	H2	X1	X0
2	H2	H3-X2	X0	H2	H3	X2	X0
3	H3	H1-X3	X0	H3	H1	X3	X0

7.3 DELTA WINDINGS

Refer to Figures 1-2 and Table 1. If possible, always inject test current to HV and LV (and measure two windings) simultaneously. This will magnetize the core more efficiently and shorten the time to get stable readings. If single-injection single-channel measurement is chosen, please note that the time for stabilization on larger transformers may be long!

Take resistance measurement with the indicated connections. Again, if time is of concern, the last test set up, which is a repeat of the first, may be omitted if all measurements are consistent when comparing one phase to the next or to previous tests.

8 INTERPRETATION OF MEASUREMENTS

Measurements are evaluated by:

- Comparing to original factory measurements;
- Comparing to previous field measurements;
- Comparing one phase to another.

The latter will usually suffice. The industry standard (factory) permits a maximum difference of 1/2 percent from the average of the three phase windings. Field readings may vary slightly more than this due to the many variables. If all readings are within one percent of each other, then they are acceptable.

Variation from one phase to another or inconsistent measurements can be indicative of many different problems:

- Shorted turns;

- Open turns;
- Defective ratio adjusting (RA) switch or LTC;
- Poor connections (brazed or mechanical).

The winding resistance test is very useful in identifying and isolating the location of suspected problems.

8.1 CONFUSION FACTORS

Apparent problems (i.e., inconsistent measurements or variations between phases) can also be the result of a number of factors which are not indicative of problems at all. Failure to recognize these factors when evaluating test data can result in confusion and possibly unwarranted concern.

8.1.1 TEMPERATURE CHANGE

The DC resistance of a conductor (hence winding) will vary as its temperature changes, for copper windings 0.39 % per degree C. This is generally not a significant consideration when comparing one phase to another of a power transformer. Loading of power transformers is generally balanced, hence temperatures should be very similar. However, when comparing to factory measurements or previous field measurements, small but consistent changes should be expected. In addition to loading, temperature variations (likewise resistance variations) can be due to:

- Cooling or warming of the transformer during test. It is not uncommon for one to two hours to pass between taking a first and last measurement when testing a large power transformer with an LTC. A transformer which has been on load can have a significant temperature change in the first few hours off-load.
- When measuring the DC resistance of smaller transformers, care should be exercised to ensure that the test current does not cause heating in the winding. The test current should not exceed 10 percent of the windings rating.

When using the WINDAX PC SW, automatic re-calculation to normalized temperature can be done and the recalculated value is reported together with the measured value.

8.1.2 CONTACT OXIDIZATION

The dissolved gases in transformer oil will attack the contact surfaces of the RA switch and LTC.

The problem is more prevalent in older transformers and heavily loaded transformers. Higher resistance measurements will be noticed on taps which are not used. (Typically a load tapchanger installed on a subtransmission system will only operate on 25-50 per cent of its taps.) This apparent problem can be rectified by merely exercising the switch. The design of most LTC and RA switch contacts incorporate a wiping action which will remove the surface oxidization. Hence, operating the switch through its full range 2 to 6 times will remove the surface oxidization.

A potential transformer installed in one phase could become part of the measured circuit and affect the measured DC resistance of that phase.

A two winding CT installed in one phase would have a similar effect. Usually donut bushing type CTS are used in power transformers. However, on rare occasions an in-line two winding CT may be encountered.

8.1.3 A MEASURING ERROR

There are many possibilities:

- A wrong connection or poor connection;
- A defective instrument or one requiring calibration;
- An operating error;
- A recording error.

8.1.4 AMBIGUOUS OR POORLY DEFINED TEST DATA

There is often more than one way to measure the resistance of a transformer winding (e.g., line terminal to line terminal or line to neutral). Typically, field measurements are taken from external bushing terminals. Shop or factory measurements are not limited to the bushing terminals.

Additionally internal winding connections can be opened (e.g. opening the corner of a delta) making measurements possible which are not practical in the field. Details of test set-ups and connections area often omitted in test reports which can lead to confusion when comparing test data.

8.2 HOW BAD IS BAD?

When a higher than expected measurement is encountered what does it mean? Is failure imminent?

Can the transformer be returned to service? Is corrective action needed? To answer these questions more information along with some analytical thinking is usually required.

- Firstly, have the confusion factors been eliminated?
- Secondly, what are the circumstances which initiated the resistance test? Was it routine maintenance or did a system event (e.g. lightning or through fault) result in a forced outage?
- Is other information available? Maintenance history? Loading? DGA? Capacitance bridge? Excitation current? If not do the circumstances warrant performing additional tests?
- Consider the transformer schematic. What components are in the circuit being measured?

Has the location of the higher resistance been isolated? See “Isolating Problems”.

- How much heat is being generated by the higher resistance? This can be calculated (I2R) using the rated full load current. Is this sufficient heat to generate fault gases and possibly result in catastrophic failure? This will depend on the rate at which heat is being generated and dissipated. Consider the mass of the connector or contact involved, the size of the conductor, and its location with respect to the flow of the cooling medium and the general efficiency of the transformer design.

9 ISOLATING PROBLEMS

The resistance test is particularly useful in isolating the location of suspected problems. In addition to isolating a problem to a particular phase or winding, more subtle conclusions can be drawn.

Consider the transformer schematic (nameplate). What components are in the test circuit? Is there an RA switch, LTC, diverter isolating switch, link board connectors, etc.? By merely examining the test data, problems can often be isolated to specific components. Consider:

9.1 RA SWITCH

In which position does the higher resistance measurement occur? Are repeat measurements (after moving the RA switch) identical to the first measurement or do they change.

9.2 LTC

The current carrying components of the typical LTC are the step switches, reversing switch and diverter switches. Carefully examine the test data looking for the following observations:

9.2.1 STEP SWITCH OBSERVATION

A higher resistance measurement occurring on a particular tap position both boost and buck (e.g., both +1 and-1, +2 and -2, etc.)

The above observation would indicate a problem with a particular step switch. Each step switch is in the circuit twice. Once in the boost direction and once in the buck direction.

9.2.2 REVERSING SWITCH OBSERVATION

All boost or buck measurements on a phase are quantatively and consistently higher, than measurements in the opposite direction or other phases.

The reversing switch has two positions, buck and boost, and operates only when the LTC travels through neutral to positions +1 and -1. Hence a poor contact would affect all boost or buck measurements. If the LTC is operated between +1 and -1 the resistance measured through a poor reversing switch contact would likely change.

9.2.3 DIVERTER SWITCH OBSERVATION

All odd step or all even step measurements in both the buck and boost direction are high.

There are two diverter switches. One is in the current circuit for all odd steps and the other for all even steps.

The foregoing discussion is only typical. LTC designs vary. To draw conclusion based on resistance measurements, the specific LTC schematic must be examined to identify the components which are being measured on each step. This information is usually available on the transformer nameplate.

9.3 CONTACTS VS CONNECTORS OR JOINTS

Is the higher resistance measurement consistent and stable when the RA switch or LTC is operated? Generally inconsistent measurements are indicative of contact problems while a consistent and stable high measurement would point to a joint or connector.

10 LIMITATIONS

The transformer resistance test has several limitations which should be recognized when performing the test and interpreting test data:

The information obtained from winding resistance measurements on delta connected windings is somewhat limited. Measuring from the corners of a closed delta the circuit is two windings in series, in parallel with the third winding (see Figure 4).

The individual winding resistances can be calculated; however this is a long tedious computation and is generally of little value. Comparison of one 'phase' to another will usually suffice for most purposes. Additionally, since there are two parallel paths an open circuit (drop out) test does not mean too much. However, the test is still recommended. Problems involving LTCs and RA switches will yield measurements which are not uniform, and often unstable and inconsistent.

Hence the resistance test will detect most problems.

The resistance of the transformer's winding can limit the effectiveness of the test in detecting problems. The lower the resistance of a winding, the more sensitive the test is with respect to detecting problems. Windings with high DC resistance will mask problems.

The detection of shorted turns is not possible in all situations. Often shorted turns at rated AC voltage cannot be detected with the DC test. If the fault is a carbon path through the turn to turn insulation it is a dead short at operating potentials. However, at test potential, 30 V DC, the carbon path may be a high resistance parallel path and have no influence on the measured resistance.

Certainly if the conductors are welded together the fault should be detectable.

It is not possible on some transformer designs to check the LTC using the resistance test (e.g., series winding). The circuit between external terminals simply excludes the LTC. On such units the resistance test is of no value in verifying the operating integrity of the LTC. If the LTC selector switch is in the main tank (i.e., same tank as windings) and cannot be physically inspected it is recommended that samples for DGA be taken as part of routine LTC maintenance.

12 REFERENCES

[1] Bruce Hembroff, "A Guide To Transformer DC Resistance Measurements, Part 1", Electricity Today, March 1996

[2] Bruce Hembroff, "A Guide To Transformer DC Resistance Measurements, Part 2", Electricity Today, April 1996

[3] "Transformer Winding Resistance Testing of Fundamental Importance", Electricity Today, February 2006

[4] IEEE Std C57.125-1991

[5] IEC Std 60076-1

TRANSFORMER RATINGS

Teal Electronics

Transformer size or capacity is most often expressed in kVA. "We require 30 kVA of power for this system" is one example, or "The facility has a 480 VAC feed rated for 112.5 kVA".

However, reliance upon only kVA rating can result in safety and performance problems when sizing transformers to feed modern electronic equipment. Use of off-the-shelf, general purpose transformers for electronics loads can lead to power quality and siting problems:

- Single-phase electronic loads can cause excessive transformer heating.
- Electronic loads draw non-linear currents, resulting in low voltage and output voltage distortion.
- Over sizing for impedance and thermal performance can result in a transformer with a significantly larger footprint.

It is vital for the system's designer to understand all of the factors that affect transformer effectiveness and performance.

THERMAL PERFORMANCE

Historically, transformers have been developed to supply 60 Hz, linear loads such as lights, motors, and heaters. Electronic loads were a small part of the total connected load. A system designer could be assured that if transformer voltage and current ratings were not exceeded, the transformer would not overheat, and would perform as expected.

A standard transformer is designed and specified with three main parameters: kVA Rating, Impedance, and Temperature Rise.

KVA RATING

The transformer voltage and current specification. KVA is simply the load voltage times the load current. A single phase transformer rated for 120 VAC and 20 Amperes would be rated for 120 x 20 = 2400 VA, or 2.4 KVA (thousand VA).

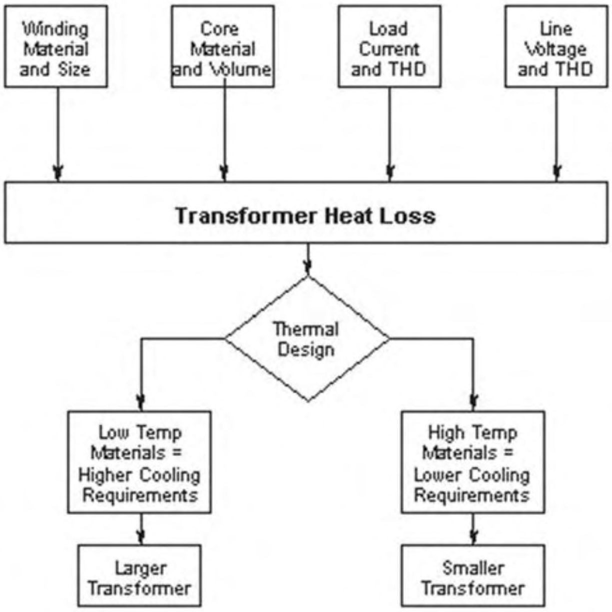
IMPEDANCE

Transformer Impedance and Voltage Regulation are closely related: a measure of the transformer voltage drop when supplying full load current. A transformer with a nominal output voltage of 120 VAC and a Voltage Regulation of 5% has an output voltage of 120 VAC at no-load and (120 VAC - 5%) at full load - the transformer output voltage will be 114 VAC at full load.

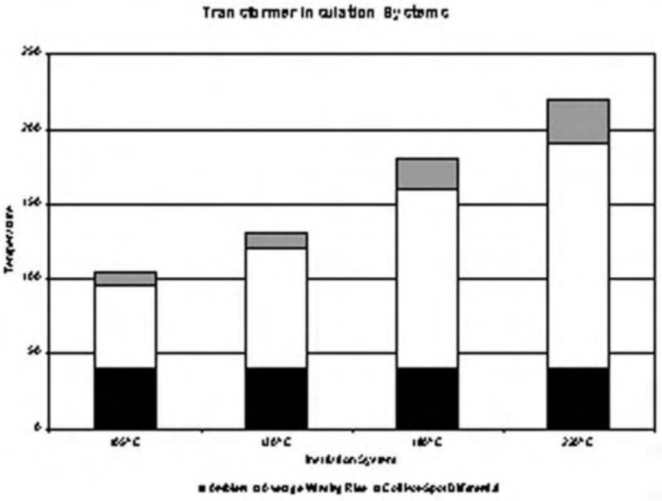
Impedance is related to the transformer thermal performance because any voltage drop in the transformer is converted to heat in the windings.

TEMPERATURE RISE

Steel selection, winding capacity, impedance, leakage current, overall steel and winding design contribute to total transformer heat loss. The transformer heat loss causes the transformer temperature to rise. Manufacturers design the transformer cooling, and select materials, to accommodate this temperature rise.



Use of less expensive material with a lower temperature rating will require the manufacturer to design the transformer for higher airflow and cooling, often resulting in a larger transformer. Use of higher quality materials with a higher temperature rating permits a more compact transformer design.



"K" FACTOR TRANSFORMER RATING

In the 1980s, power quality engineers began encountering a new phenomenon: non-linear loads, such as computers and peripherals, began to exceed linear loads on some distribution panels. This resulted in large harmonic currents being drawn, causing excessive transformer heating due to eddy-current losses, skin effect, and core flux density increases.

Standard transformers, not designed for non-linear harmonic currents, were overheating and failing even though RMS currents were well within transformer ratings.

In response to this problem, IEEE C57.110-1986 developed a method of quantifying harmonic currents. A "k" factor was the result, calculated from the individual harmonic components and the effective heating such a harmonic would cause in a transformer. Transformer manufacturers began designing transformers that could supply harmonic currents, rated with a "k" factor. Typical "K" factor applications include:

K-4: Electric discharge lighting, UPS with input filtering, Programmable logic controllers and solid state controls

K-13: Telecommunications equipment, UPS systems, multi-wire receptacle circuits in schools, health-care, and production areas

K-20: Main-frame computer loads, solid state motor drives, critical care areas of hospitals

"K" factor is a good way to assure that transformers will not overheat and fail. However, "K" factor is primarily concerned with thermal issues. Selection of a "K" factor transformer may result in power quality improvement, but this depends upon manufacturer and design.

TRANSFORMER IMPEDANCE

Transformer impedance is the best measure of the transformer's ability to supply an electronic load with optimum power quality. Many power problems do not come from the utility but are internally generated from the current requirements of other loads.

While a "K" factor transformer can feed these loads and not overheat, a low impedance transformer will provide the best quality power. As an example, consider a 5% impedance transformer. When an electronic load with a 200% inrush current is turned on, voltage sag of 10% will result. A low impedance transformer (1%) would provide only 2% voltage sag - a substantial improvement.

Transformer impedance may be specified as a percentage, or alternately, in Ohms (W) from Phase-Phase or Phase-Neutral.

HIGH FREQUENCY TRANSFORMER IMPEDANCE

Most transformer impedance discussions involve the 60 Hz transformer impedance. This is the power frequency, and is the main concern for voltage drops, fault calculations, and power delivery. However, non-linear loads draw current at higher harmonics. Voltage drops occur at both 60 Hz and higher frequencies.

It is common to model transformer impedance as a resistor, often expressed in ohms. In fact, a transformer behaves more like a series resistor and inductor. The voltage drop of the resistive portion is independent of frequency; the voltage drop of the inductor is frequency dependent.

Standard Transformer impedances rise rapidly with frequency. However, devices designed specifically for use with non-linear loads use special winding and steel lamination designs to minimize impedance at both 60 Hz and higher frequencies. As a result, the output voltage of such designs is far better quality than for standard transformers

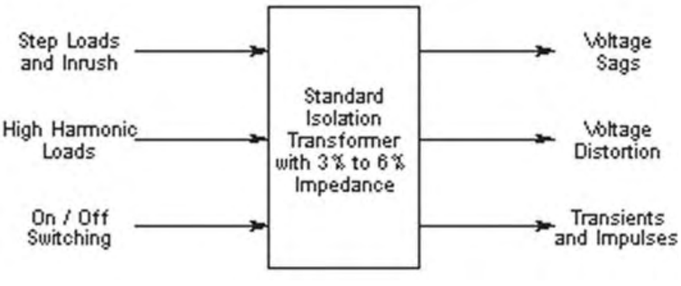
RECOMMENDATIONS FOR TRANSFORMER SIZING

System design engineers who must specify and apply transformers have several options when selecting transformers.

DO IT YOURSELF APPROACH

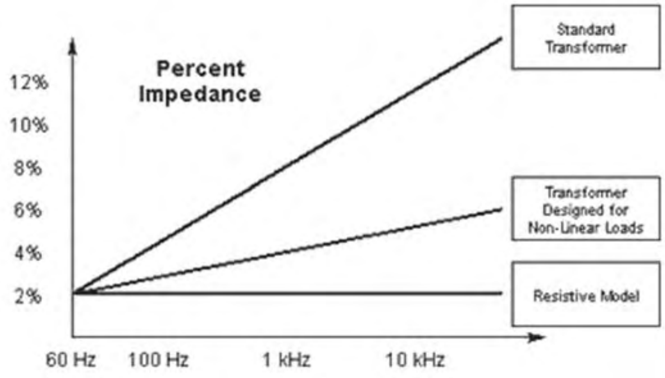
With this approach, a larger than required standard transformer is specified in order to supply harmonic currents and minimize voltage drop. Transformer over-sizing was considered prudent design in the days before transformer manufacturers understood harmonic loads, and remains an attractive option from a pure cost standpoint. However, such a practice today has several problems:

- A larger footprint and volume than low impedance devices specifically designed for non-linear loads
- Poor high frequency impedance
- Future loads may lead to thermal and power quality problems



"K"-FACTOR RATED TRANSFORMERS

Selecting and using "K"-factor rated transformers is a prudent way to ensure that transformer overheating will not occur. Unfortunately, lack of standardization makes the "K" factor rating a measure only of thermal performance, not impedance or power quality.



Some manufacturers achieve a good "K" factor using design techniques that lower impedance and enhance power quality, others simply de-rate components and temperature ratings. Only experience with a particular transformer manufacturer can determine if a "K" factor transformer addresses both thermal and power quality concerns.

TRANSFORMERS DESIGNED FOR NON-LINEAR LOADS

Transformers designed specifically for non-linear loads incorporate substantial design improvements that address both thermal and power quality concerns. Such devices are low impedance, compact, and have better high frequency performance than standard or "K" factor designs. As a result, this type of transformer is the optimum design solution.

This type of transformer may be more expensive than standard transformers, due to higher amounts of iron and copper, higher quality materials, and more expensive winding and stacking techniques. However, the benefits of such a design in power quality and smaller size justify the extra cost and make the low impedance transformer the most cost effective design overall.

NEW MEASUREMENT METHODS TO CHARACTERIZE TRANSFORMER CORE LOSS AND COPPER LOSS IN HIGH FREQUENCY SWITCHING MODE POWER SUPPLIES

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I. INTRODUCTION

Measurement methods are widely used for transformer core loss and copper loss characterization due to the potential for higher accuracy in comparison to simple conventional analytical methods. Unfortunately, no measurement methods are available that can measure the transformer core loss and copper loss under the actual operation conditions in switching mode power supplies (SMPS).

The existing measurement methods determine transformer core loss under sinusoidal excitation using an impedance or network analyzer [1],[2]. However, the pulse width modulation (PWM) waveforms in SMPS are not sinusoidal, but are rectangular. In addition, converters such as the flyback and asymmetrical half-bridge (AHB) contain a DC bias in the magnetizing current, but these methods cannot account for the DC bias. Furthermore, due to the highly non-linear nature of the B-H property of ferrite materials, Fourier analysis can yield completely erroneous results. Therefore, the impedance or network analyzer method cannot be applied to accurately determine the core loss in high frequency switching converters.

In [3] and [4], two measurement setups were designed to experimentally determine transformer core loss. In [3], sine waveforms were used to obtain the core loss curves for the ferrite materials. In addition, no core loss results for switching converters are provided. In [4], a method is proposed to measure transformer core loss for a SMPS using a waveform generator and a power amplifier.

Unfortunately, using these techniques, the core loss cannot be determined if the transformer under test operates with a DC bias in the magnetizing current. It is also noted that an error analysis of the proposed methods was not conducted and the corresponding measurement accuracy was not provided. Therefore, if these techniques are used, the user cannot interpret the accuracy of their results. To overcome the limitations of the existing methods, an improved method to determine transformer core loss in high frequency SMPS is proposed, which is suitable for core loss measurement under PWM excitation, with or without a DC bias.

In [5], a method is proposed to calculate transformer copper loss by measuring winding AC resistance for each harmonic in the PWM current. The method uses sinusoidal waveforms in the measurement and not the rectangular PWM waveforms under the transformer operating conditions. The drawback to this technique is that it does not replicate the field pattern within the transformer. In addition, the measurements are time-consuming. Another disadvantage of this method is that the results only provide information about winding self-resistance. When both the primary and secondary windings have current flowing through them at the same time, the field interaction due to proximity effect induces a mutual resistance between them, which can significantly reduce the total transformer copper loss. Therefore, an "in-component" measurement scheme for transformer AC winding resistance is proposed. The method uses the PWM current waveforms, so, the mutual resistance between windings is inherently included, which yields increased accuracy.

In section II, the core loss measurement method is proposed. In section III, the proposed copper loss measurement method is presented. The experimental verification is provided in section IV. In section V, a detailed error analysis is presented for each method. The conclusions are presented in section VI.

II. PROPOSED CORE LOSS MEASUREMENT METHOD

The proposed transformer core loss measurement test setup is shown in Figure 1. With the secondary side opencircuit, the averaged core loss PCore over one switching period T can be determined from the primary voltage vpri(t) and the magnetizing current iM(t) using (1).

$$P_{Core} = \frac{1}{T}\int_0^T v_{pri}(t)\cdot i_M(t)\,dt \tag{1}$$

Due to the leakage inductance and resistance associated with the primary winding, the winding voltage cannot be measured directly. However, the secondary side voltage vsec(t) can be measured and reflected back to the primary side using the turns ratio. Since the secondary winding is open circuit, the only primary terminal current is the magnetizing current, which is sensed using a resistor RSense.

By measuring the secondary voltage and the voltage across a sensing resistor, we can obtain the averaged core loss over one switching period T using (2).

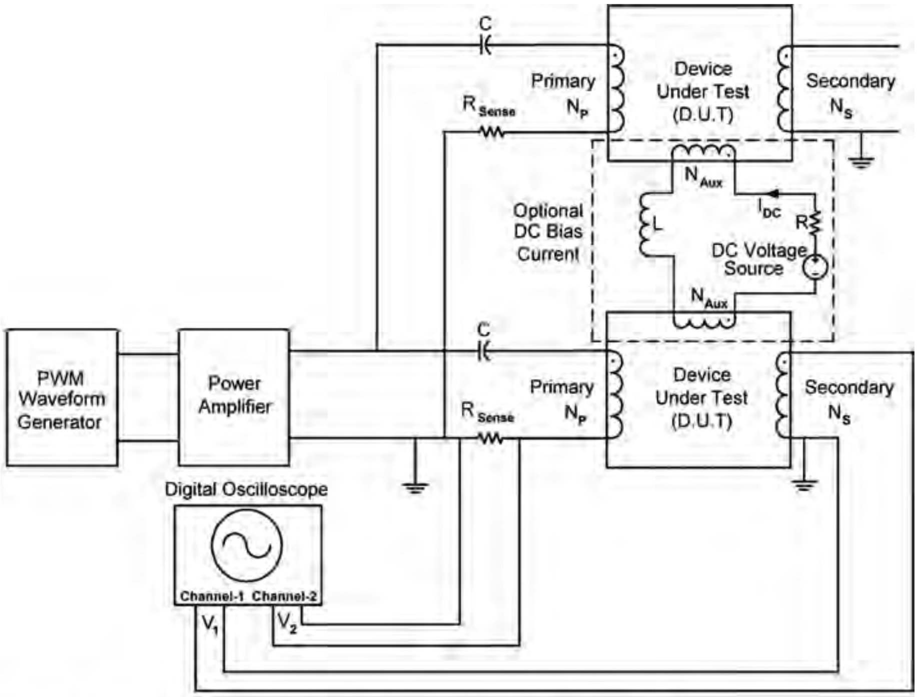


Figure 1 Proposed core loss measurement test setup

Using a digital oscilloscope with channel math capabilities, (2) can be evaluated directly using the oscilloscope. In (2), NP and Ns are the primary and secondary winding turns; v1i and v2i are the ith sample of the measured voltage values of the secondary side and current sensing resistor; N is the number of the samples in one switching period.

$$P_{Core} = \frac{N_p}{N_s}\frac{1}{N}\sum_{i=1}^{N} v_{1i} \cdot \frac{v_{2i}}{R_{sense}} \tag{2}$$

The practical implementation issues of the measurement setup are explained as follows:

1) POWER SOURCE

A PWM waveform generator (function generator) and an RF power amplifier (3MHz bandwidth) are used to provide the PWM voltage source to the transformer.

2) CURRENT SENSING DEVICE

A low-inductive metal film resistor is used to measure the magnetizing current. In order to minimize the distortion on the waveform and at the same time to reduce the phaseshift error, ten 10Ω±1% metal film resistors were connected in parallel. The impedance characteristic of the resistor combination is flat up to 5MHz.

3) DC BIAS CURRENT

An optional auxiliary winding can be introduced to provide the equivalent DC magnetomotive force to the core for transformers that operate with a DC bias component in the magnetizing current. A 2mH inductor was connected in the auxiliary circuit to reduce the high frequency AC ripple.

In addition, two auxiliary windings with the same number of turns were connected with opposite polarities to eliminate the AC voltage from the primary winding. The second auxiliary winding is connected into the same transformer as the one under test.

In order to ensure the measurement of the transformer core loss is accurate and to eliminate error from a variety of sources, three key steps are proposed in the following subsections.

A. CALIBRATION OF THE WINDING TURNS RATIO

The proposed core loss measurement method has two ports.

Due to the non-ideal magnetic coupling, parasitic air flux and the winding terminations, the primary and secondary winding terminal voltage ratio can vary slightly from the designed turns ratio. In order to minimize this error, the winding turns ratio should be calibrated. For the turns ratio calibration, a sinusoidal wave can be used to simplify the process. The turns ratio result can be applied to the rectangular PWM waveforms under test. The terminal voltages (peak or peak-to-peak value) of the primary and secondary windings are measured and the actual turns ratio is calculated using (3), which is then used in (2). The calibration should be conducted over a range of frequencies.

$$N_{Turns-Ratio} = V_{\Pr i} / V_{Sec} \tag{3}$$

B. CURRENT SENSING RESISTANCE CALIBRATION

Some error will be introduced into the core loss measurement due to the tolerance and the associated inductance of the current sense resistor. A good approach is to calibrate the resistor's frequency response using the impedance analyzer to ensure its frequency response remains flat for several harmonics of the switching frequency.

C. AVERAGING DATA

Averaging should be adopted for the data processing.

The core loss for each operating condition should be tested ten times and then the values should be averaged.

III. PROPOSED COPPER LOSS MEASUREMENT METHOD

The objective of transformer copper loss measurement is to obtain an equivalent AC resistance for each winding under the actual operating conditions. To proceed, it is important to clarify the following two concepts:

1) We need to define the current wave shape used in the measurement under the SMPS operating conditions. By analyzing the SMPS circuits, the currents flowing through the windings can usually be well approximated as a rectangular wave shape (unipolar or bipolar) of the corresponding duty ratio by neglecting the small ripple [6].

Therefore, a rectangular PWM current can be used in measuring the transformer copper loss. In this article, a bipolar rectangular PWM waveform is used.

2) A transformer is a multi-winding structure, so, the field interaction between the primary and secondary windings

induces a mutual resistance. Fortunately, we don't need to obtain the mutual resistance information. What we need is an equivalent AC resistance of each winding under the operating condition, which includes the mutual resistance information.

The proposed transformer winding AC resistance measurement scheme is shown in Figure 2. By applying the rectangular PWM voltage in the primary side from the waveform generator and power amplifier, the corresponding magnetic field is established within the transformer and a PWM voltage is induced in the secondary side. If a resistive load is connected on the secondary side, a rectangular current will flow through the load resistor and the secondary winding equivalent AC resistance. The secondary side current iSec can be obtained by measuring the voltage across the load resistor. An auxiliary winding is added to measure the secondary winding terminal voltage. This winding can be easily added externally around the core since it does not carry any current. The two voltages are then measured using a digital oscilloscope. Then the averaged power of the secondary winding PSec and the power of the load resistor PLoad can be calculated over one switching period.

Therefore, the secondary winding equivalent AC resistance can then be calculated using (4), where NSec and NAux are the secondary and auxiliary winding turns; v1i and v2i are the ith sample of the voltage values; and N is the number of the samples in one switching period.

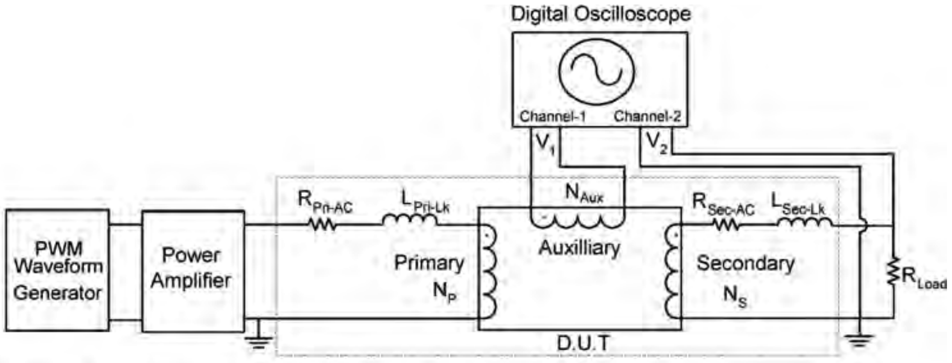


Figure 2 Proposed copper loss measurement test setup

$$R_{Sec-AC} = \frac{P_{Sec} - P_{Load}}{I^2_{SecRMS}} = \frac{\frac{N_{Sec}}{N_{Aux}}\frac{1}{N}\sum_{i=1}^{N} v_{1i}\cdot\frac{v_{2i}}{R_{Load}}}{\frac{1}{N}\sum_{i=1}^{N}\left(\frac{v_{2i}}{R_{Load}}\right)^2} - R_{Load} \qquad (4)$$

By defining the corresponding functions in the digital oscilloscope, the power of the measured winding and the RMS current value over one switching period can be obtained easily and used in the winding resistance calculation. In order to measure the primary winding AC resistance, the secondary winding should be excited.

In order to ensure the measurement of the transformer copper loss is accurate and to eliminate error from a variety of sources, three key steps are proposed in the following subsections.

A. CALIBRATION OF THE WINDING TURNS RATIO

In the proposed transformer winding AC resistance measurement method, a third winding is used to obtain the terminal voltage of the measured winding. The actual winding turns ratio between the measured winding and the third winding should be calibrated in order to achieve accurate results. This can be achieved using the procedure outlined in section II.

A. LOAD RESISTANCE CALIBRATION

Since a resistor is used as the load in measuring the winding AC resistance, the resistor's tolerance and frequency response can have a significant impact on measurement results. In order to minimize any error introduced by the resistor, the resistor's frequency response should be measured using an impedance analyzer to obtain an accurate resistance value and phase response.

B. AVERAGING DATA

As in the core loss calculation, the copper loss data in the winding AC resistance measurement should be averaged in order to minimize any random error in the measurements.

IV. MEASUREMENT RESULTS AND VERIFICATION

A high frequency planar transformer was tested to verify the proposed core loss and copper loss methods. In order to verify the loss measurement results, a time-domain Finite Element Analysis solver from ANSOFT was used.

A multi-winding planar transformer was used in an AHB DC/DC converter with unbalanced secondary windings [7].

The converter diagram is shown in Figure 3. The specifications of the converter and the transformer parameters are:

Input: 35-75V, nominal at 48V, output: 5V/25W

Switching frequency: 400kHz

Main winding turns: Np: Ns1: Ns2 = 6:1:3

Core: E18/4/10 planar cores (EE combination)

Winding: 1oz (35micrometres) copper on a 10-layer PCB

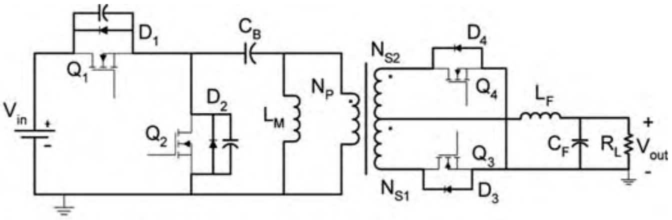


Figure 3 AHB converter diagram

Due to the complementary duty cycle operation and unbalanced secondary windings, the converter operates with a DC bias (IM-DC) in the magnetizing current. It can be calculated using (5).

$$I_{M-DC} = (1-D)I_o\frac{N_{s2}}{N_p} - DI_o\frac{N_{s1}}{N_p} \qquad (5)$$

In the transformer design, an air gap of 67 micrometres was added to the core central leg to avoid saturation. The proposed optional circuit to create the DC bias current for the test setup was used in the core loss measurement.

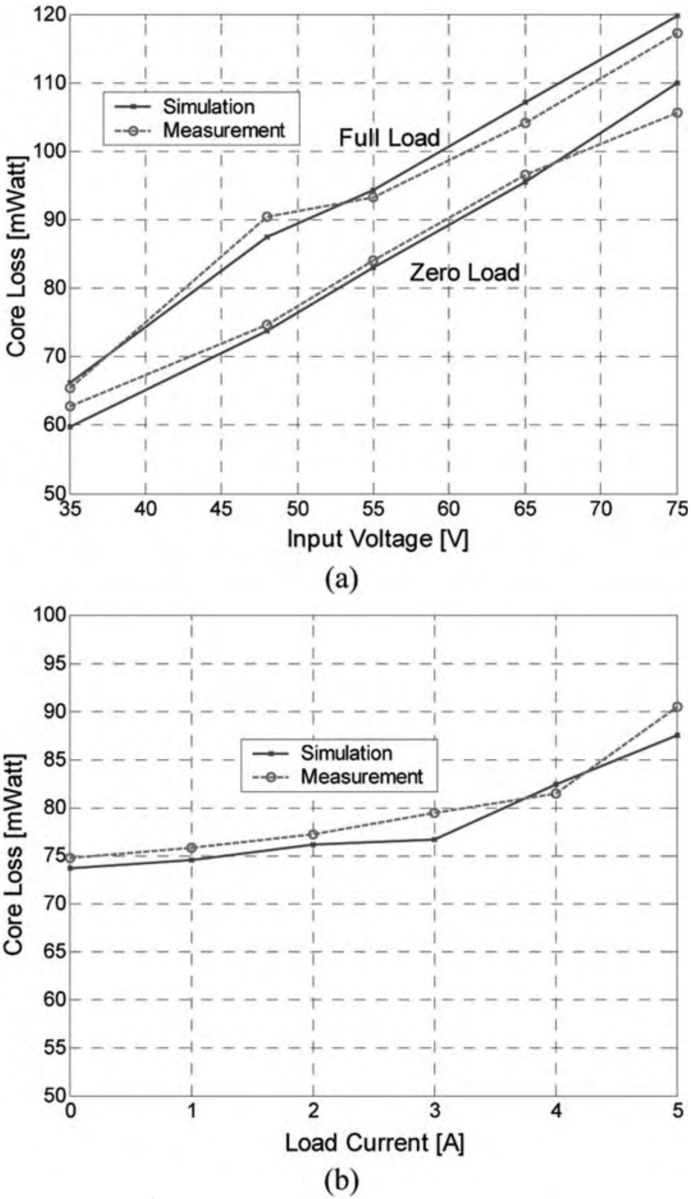
A. CORE LOSS MEASUREMENT RESULTS

The following three operating conditions of the AHB transformer were tested using the proposed method.

1) Vin=35-75V range @ no load
2) Vin=35-75V range @ 5A load
3) Vin=48V @ 0-5A load range

The measurement results and FEA simulation results are provided in Figure 4. In order to illustrate the effect of the DC bias current on the ferrite core loss, Figure 4(a) shows the core loss measurement and simulation results under operating conditions 1) and 2). Figure 4(b) provides the results for operating condition 3). The core losses under the equivalent 400kHz sine waveform and bipolar square waveform (D=50%) with no DC bias current condition were also tested for comparison purposes.

Some typical core loss measurement waveforms under operating condition 1 are shown in Figure 5. The digital oscilloscope math functions implement (2). The results are indicated on the right side of the figure.



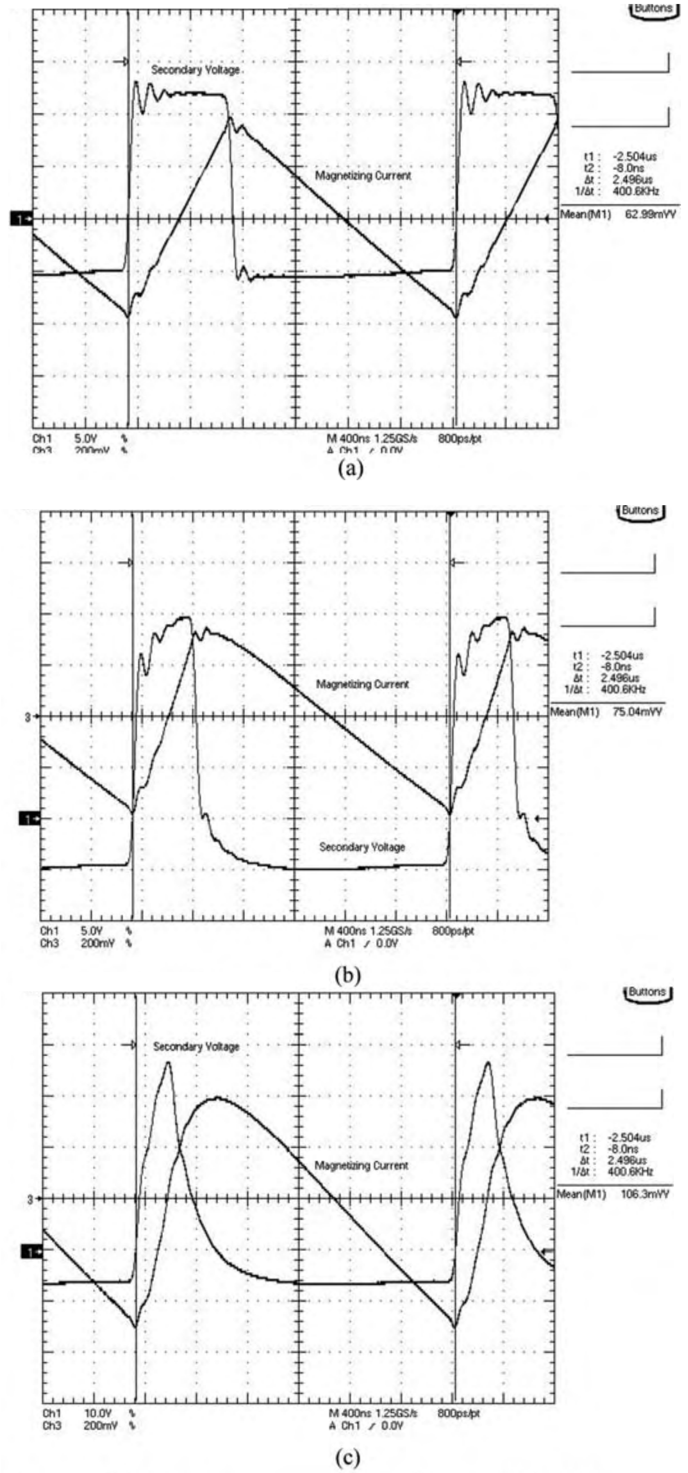
(a)

(b)

Figure 4 AHB transformer core loss results

It is clear from the test results that the core loss under PWM waveform excitation increases as the duty ratio decreases and that the addition of a DC bias current increases core loss.

Using the FEA simulation result as the reference, the difference between the measurement and the FEA simulation is within plus or minus 5% for all the measurement conditions.



(a)

(b)

(c)

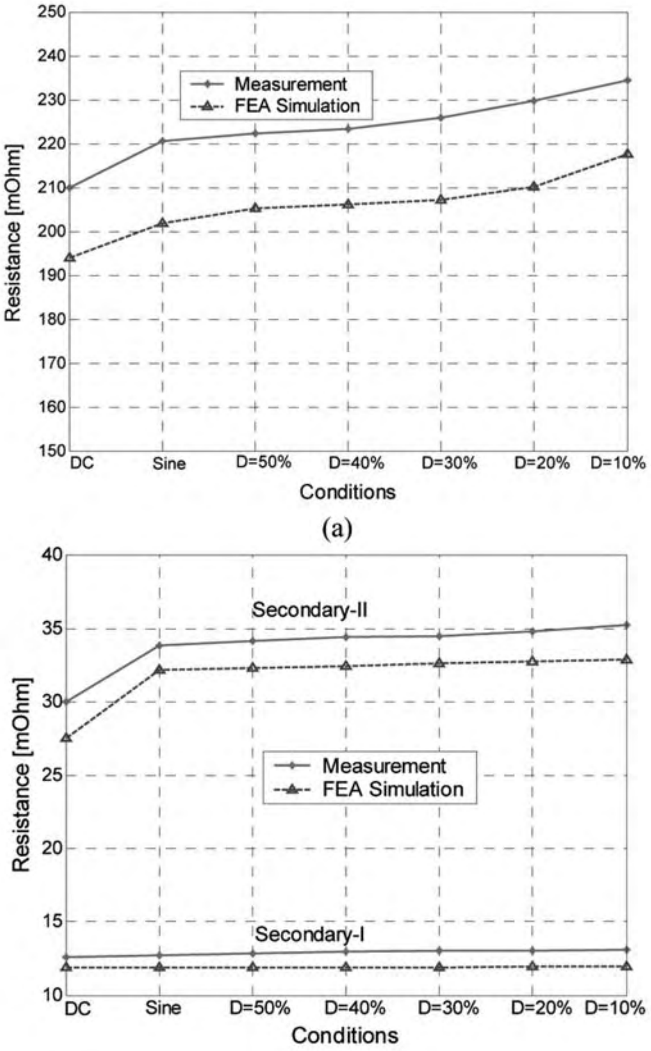
Figure 5 AHB core loss measurement waveforms: (a) Vin=35V, (b) Vin=48V, (c) Vin=75V

A. WINDING AC RESISTANCE MEASUREMENT RESULTS

The AC resistance of the AHB transformer power windings were measured and 3D FEA simulations were conducted to compare the results. The measurement and FEA simulation results are illustrated in Figure 6. The DC resistances are also provided as a reference.

Using the simulation results as reference, the difference between the measurement and FEA simulation results are within plus or minus 10% for the three AHB transformer powertrain windings. The measurement waveforms are shown for the secondary-I winding in Figure 7.

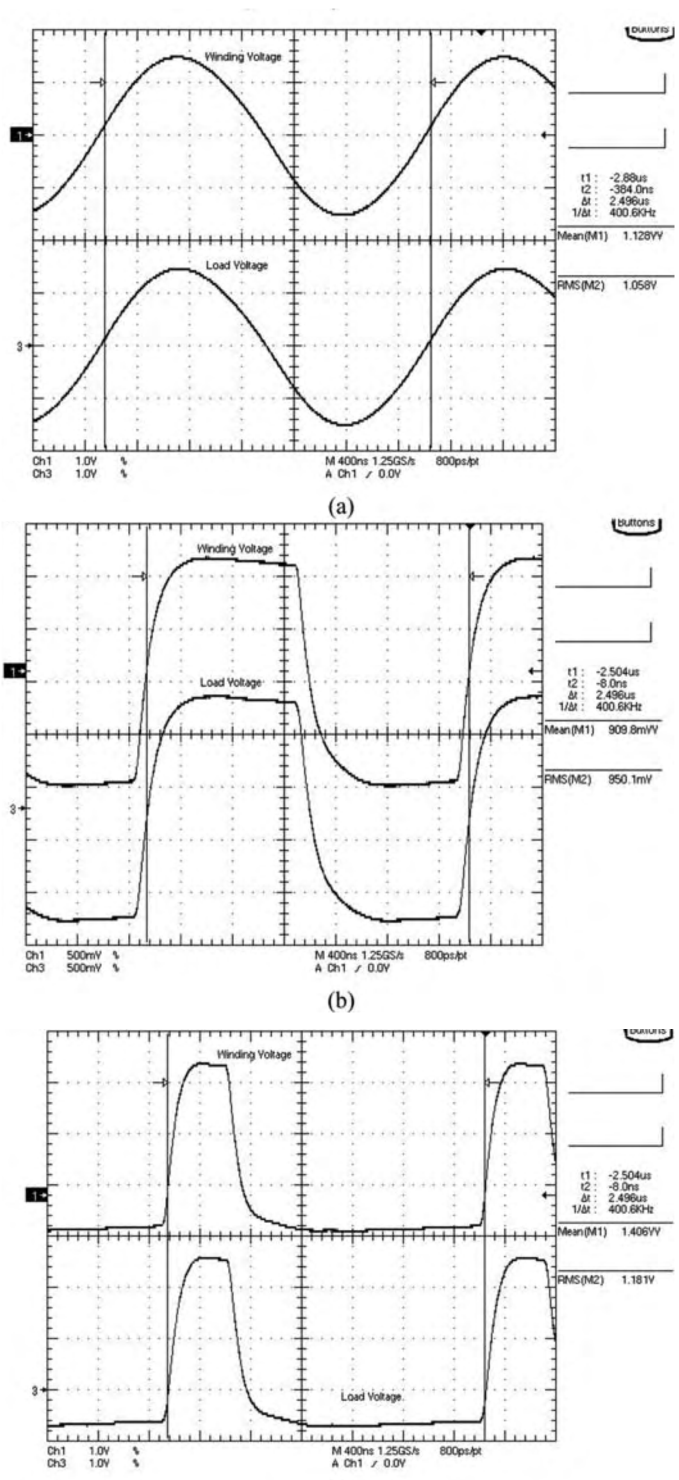
We can observe from the test results that the winding equivalent AC resistance under PWM waveform excitation is larger than that under sinusoidal excitation. In addition, the resistance increases as the duty ratio decreases.



(a)

(b)

Figure 6 AHB transformer winding AC resistance; (a) primary winding, and (b) secondary windings



(a)

(b)

(c)

Figure 7 AHB transformer secondary-I winding AC resistance measurement waveforms; (a) sinusoidal, (b) D=50%, and (c) D=20%

V. ERROR ANALYSIS

In order to ensure that the core loss and winding AC resistance measurements are accurate and valid, it is necessary to analyze the various error sources in the measurements to obtain the loss measurement accuracy.

A. ERROR ANALYSIS FOR CORE LOSS MEASUREMENT

Using (2), the core loss is determined using the winding voltage and magnetizing current. Therefore, the error analysis of the proposed core loss measurement method is based on (2). The various error sources and their effect on the core loss measurement accuracy are analyzed as follows.

1) VOLTAGE MEASUREMENT ERROR

The Tektronix TDS5054 digital oscilloscope was used for the tests. It has an 8-bit ADC. The averaging acquisition mode was used in the measurement, so, the effective sampling resolution can be as high as 11-bit. Both the digitizing and the linearity errors in the measurement are ±1/2LSB at full scale. Combining these factors, we can assume that the voltage measurement error is ±1LSB at full scale.

For the measurements, the location of the peak value of the voltage waveform measured on the oscilloscope determines the voltage measurement error. In the measurement, the peak value is always kept above 10% of the full scale (for the worst case). For the vertical scale, the voltage measurement error of the oscilloscope is less than 0.489%. Therefore, from (2), the relative error of the worst case core loss due to the voltage measurement is given by (6), which is less than 1% for the given test setup.

$$\frac{\Delta P_{Core}}{P_{Core}} = \left| \frac{\frac{N_p}{N_s}\frac{1}{N}\sum_{i=1}^{N} v_{1i}(1\pm 0.489\%)\cdot\frac{v_{2i}(1\pm 0.489\%)}{R_{sense}}}{\frac{N_p}{N_s}\frac{1}{N}\sum_{i=1}^{N} v_{1i}\cdot\frac{v_{2i}}{R_{sense}}} - 1 \right| = 0.98\% \qquad (6)$$

2) TURNS RATIO ERROR

As explained in section II, calibration of the turns ratio between the primary and secondary windings helps to minimize error. In the turns ratio calibration procedure, (3) is used for the calculation. The peak voltage is kept close to the full scale of the oscilloscope, so, the digitizing error in the voltage measurement for the turns ratio calibration can be considered as ±1LSB of the ADC, which is 2-11.

Therefore, based on (3), the worst-case relative error for the turns ratio calibration is less than 0.1%.

In this article, the digitizing error is neglected, so, we can assume that no error is introduced into the calibration procedure of the turns ratio. Using this calibration method, the turns ratio between the primary and secondary-II winding in the AHB transformer is 2.04 from 400kHz to 2MHz. Without this turns ratio calibration, a relative error of 2% will be introduced into the core loss measurement results.

3) TOLERANCE OF THE CURRENT SENSING RESISTOR

The metal film resistor used in the core loss measurement has a tolerance of plus or minus 1%. Therefore, a 1% relative error is introduced due to the current sensing resistor.

4) TIME DELAY ERROR

Another important error source is time delay error due to the inductance of the current sensing resistor. For SMPS transformers, ideally, the voltage and current waveforms are in the wave shapes as shown in Figure 8 by the solid lines.

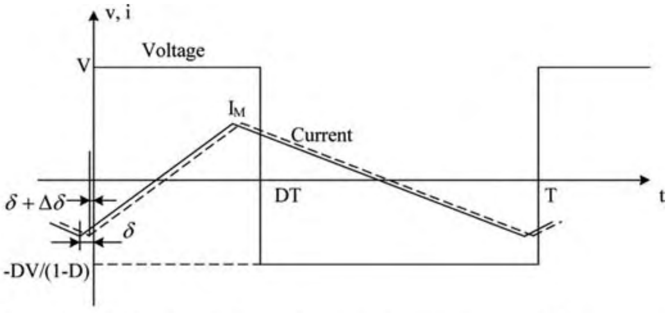


Figure 8 Ideal and typical transformer voltage and magnetizing current

The time delay between the voltage and the magnetizing current can be defined as d. Then, from (1), (7) can be derived. In (7), V is the amplitude of the positive part of voltage waveform; IM is the amplitude of the magnetizing current; D is the duty ratio of the PWM waveform; T is the switching period of the circuit; and d is the time delay between the voltage and the magnetizing current.

$$P_{Core} = V \cdot I_M \cdot \frac{2D\delta T - 2D^2\delta T - \delta^2}{(1-D)^2 DT^2} \qquad (7)$$

Since the magnetizing current is sensed by a resistor, (7) can be written as (8).

$$P_{Core} = V \cdot \frac{V_R}{R_{Sense}} \cdot \frac{2D\delta T - 2D^2\delta T - \delta^2}{(1-D)^2 DT^2} \qquad (8)$$

If some error, Delta d is introduced into the time delay, d the magnetizing current waveform will be shifted with respect to the actual waveform as illustrated by the dashed line in Figure 8. Then the incremental core loss due to this error can be calculated using (9).

$$\Delta P_{Core} = \frac{\partial P_{Core}}{\partial \delta}\Delta\delta \qquad (9)$$

Using (8) and (9), the relative error of the core loss power due to Delta d is given by (10).

$$\left|\frac{\Delta P_{Core}}{P_{Core}}\right| = \left|\frac{2DT - 2D^2T - 2\delta}{2D\delta T - 2D^2\delta T - \delta^2}\right| |\Delta\delta| \qquad (10)$$

When d <<DT and D<<D2T, (10) can be approximated by (11).

$$\left|\frac{\Delta P_{Core}}{P_{Core}}\right| \approx \left|\frac{\Delta\delta}{\delta}\right| \qquad (11)$$

It is clear that the relative error is very sensitive to small values of d. In this case, if large time delay error is introduced, the relative error will become large. Therefore, care should be taken to minimize time delay error.

Sources of time delay error can be: poor frequency response of the current-sensing device; and trigger jitter and delays for different channels introduced by the oscilloscope.

For the digital oscilloscope used, the trigger jitter is typical at 8 ps, so, it can be ignored. The probes used for the voltage measurement are originally from the same oscilloscope and are matched to each other, so, the phase delay between channels of the oscilloscope can be neglected. The inductance associated with the current sensing resistor is the important source of the phase delay error. Therefore, in experiments, care should be taken to reduce these error sources and small inductance metal film resistor is used.

Using an impedance analyzer, phase shift less than 0.01 degree is observed for the current sensing resistor at 400kHz. It is less than 0.02 degrees at 800kHz and 0.05 degrees at 2MHz. Using the phase shift at 400kHz and transferring it to delay time for 400kHz, the time error can be calculated as given by (12).

$$\Delta\delta = \frac{0.01^\circ}{360^\circ} \times 2.5\mu s = 69.5ps \qquad (12)$$

The relative error depends on the time delay and the error introduced due to the time delay, so the value changes for different operating conditions. For example, the time delay between the voltage and magnetizing current can be calculated as d=59ns using (8) for the AHB transformer operating at 48V input. With a time delay error of Delta d=69.5ps introduced by the current sensing resistor, we can obtain the relative core loss error as less than 0.12% using (10). This calculation procedure can be applied for other operating conditions and a relative error of less than 0.2% is obtained for all the operating conditions.

B. Error Analysis for Copper Loss Measurement

The main error sources in the winding resistance measurement are: (1) voltage measurement error, (2) turns ratio error, (3) tolerance of the load resistor, (4) time delay introduce into the load current measurement.

By manipulating (4), (13) can be derived.

$$R_{Sec-AC} = R_{Load} \cdot \left(\frac{\frac{N_{Sec}}{N_{Aux}} \cdot \sum_{i=1}^{N} v_{1i} \cdot v_{2i}}{\sum_{i=1}^{N} (v_{2i})^2} - 1 \right) \qquad (13)$$

The effect of each error source on the winding AC resistance measurement is analyzed as follows.

1) VOLTAGE MEASUREMENT ERROR

The TDS5054 uses one ADC for all four channels. Therefore, the digitizing errors of the voltage measurement for each channel can be considered equal. Furthermore, the digitizing error will cancel out in the numerator and denominator in the first item in (13), so we can assume that the digitizing error can be neglected.

2) TURNS RATIO ERROR

An auxiliary winding is used to obtain the winding voltage. Since a calibration of the turns ratio is carried out to obtain the actual turns ratio, this error can be ignored.

3) TOLERANCE OF THE LOAD RESISTOR

The load resistor used in the measurement has a tolerance of plus or minus 1%, so a relative error of 1% is introduced into the winding AC resistance measurement.

4) TIME DELAY ERROR

In the load current measurement, a pure resistor value is assumed as the load. However, the inductance of the resistor and the inductance induced in the measurement circuit will introduce some time shift error for the current.

For a SMPS with a rectangular PWM voltage and current waveform as shown in Figure 9 (the leakage inductance can be neglected because it is very small), the winding AC resistance can be calculated using (14), where, V1 is the positive amplitude of the auxiliary winding voltage; V2 is the positive amplitude of the load resistor voltage; and NTurn-Ratio is the actual turns ratio between the auxiliary and the measured windings after calibration.

$$R_{Sec-AC} = R_{Load} \cdot (N_{Turn-Ratio} \cdot \frac{V_1}{V_2} - 1) \qquad (14)$$

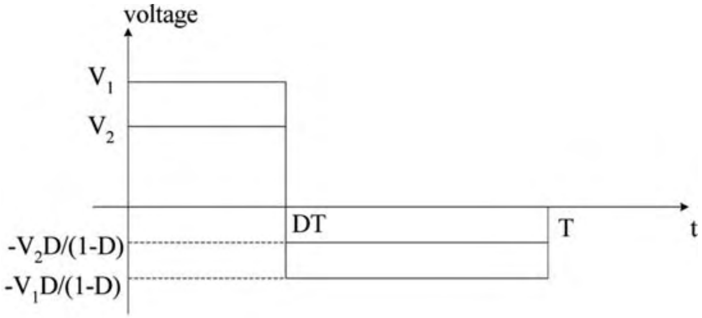


Figure 9 Typical and ideal PWM voltage and current waveform in measuring winding AC resistance

Due to the parasitic inductance, some time delay will be introduced into the load current measurement as shown in Figure 10. With this time delay, the winding AC resistance is given by (15).

$$R_{Sec-AC} = R_{Load} \left[N_{Turn-Ratio} \cdot \frac{V_1}{V_2} \left(1 - \frac{\delta}{D(1-D)T} \right) - 1 \right] \qquad (15)$$

Then, the relative error due to the time delay can be calculated using (16).

$$\frac{\Delta R_{Sec-AC}}{R_{Sec-AC}} = \frac{\frac{\delta}{D(1-D)T}}{1 - \frac{V_2}{N \cdot V_1}} \qquad (16)$$

If the load resistor is much larger than the winding AC resistance, then the ratio of V2/V1 in (16) will be very close to one. In this case, the relative error will be very sensitive to the time delay and care should be taken to minimize the parasitic inductance in the measurement.

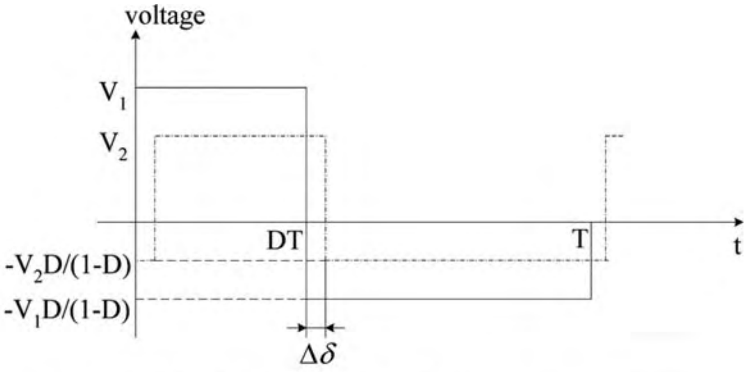


Figure 10 Time delay introduced into the load current measurement

VI. CONCLUSIONS

New measurement schemes to characterize transformer core loss and copper loss for SMPS were proposed.

Measurement results were presented for a planar transformer operating in a DC/DC power converter. FEA simulation using a time-domain solver was used to verify the measurement results. In addition, a detailed error analysis has been provided for the proposed core loss and copper loss measurement methods. The results show that the proposed methods can provide accurate measurement of transformer core loss and copper loss for high frequency SMPS.

Using the error analysis results, the relative error was calculated to be less than 5% for all the measurement conditions for the AHB transformer core loss; For the winding AC resistance, the measurement accuracy is: <2% for the primary winding, <5% for the secondary-I winding and <4% for the secondary-II winding.

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HOW TO WITNESS TEST A TRANSFORMER

Patrick K. Dooley, Virginia Transformer Corp.

Before a manufacturer sends a transformer to your site, it conducts various tests. To ensure performance requirements, you may want to witness the testing and inspect the unit yourself.

Does a new transformer represent a major expenditure for your company? Not only does such an investment cost thousands of dollars, but it's also vital to the ongoing operation of your business. Reliability is obviously a top priority here. So, how do you ensure equipment integrity and performance? Witness testing is one way to make sure your new transformer meets industry standards and will provide quality performance after installation.

About 75% of the transformers purchased by utilities undergo witness testing, compared to about 10% of those built for industrial/commercial applications. Witness testing is also more common for larger, complicated designs. Often, as customers forge a strong working relationship with a manufacturer, they're less likely to witness test every transformer. What does witness testing require? Just a visit to the plant to examine the new transformer and watch it perform during various tests. The success of a witness test depends on proper preparation by the manufacturer and you, the purchaser. Here are some useful tips.

FOR THE MANUFACTURER:

- Notify inspector, who will witness the test two weeks in advance of test date to confirm schedule. Then, verify this information three working days before the test.
- Complete routine tests before the inspector arrives to prevent delays in witness testing. However, you, as the inspector, may wish to witness the routine tests.
- Confirm calibration of instruments as scheduled. Use standard data sheets to record test values.
- Provide test certification and data sheets as standard documentation. (See ANSI/IEEE C57.12.90-1993, IEEE Standard Test Code for Liquid-Immersed Distribution, Power and Regulating Transformers and IEEE Guide for Short Circuit Testing of Distribution and Power Transformers, and C57.12.91-1995, IEEE Standard Test Code for Dry-Type Distribution and Power Transformers, for minimum information on test requirements.)

FOR THE CUSTOMER:

- Completely understand the tests you'll witness.
- Designate someone as the inspector when you place the order for the transformer. Notify the manufacturer so you or your representative receives all applicable documentation.
- Notify the manufacturer of any discrepancies in documentation.
- Accommodate the manufacturer's schedule to avoid possible cost overruns.
- Review all test documentation before arriving at the plant so you're familiar with the design parameters.

WHAT TO DO AT THE SITE:

- Review the purpose of the tests and any associated procedures with the manufacturer's test engineer prior to commencing the tests.
- Discuss which tests are of particular importance so the manufacturer can give them extra attention.

WHAT TO LOOK FOR DURING TESTING:

- Understand how to read results and how they impact performance.
- Listen to the transformer's sound level when the technician applies voltage, particularly if you've requested a sound test.
- Allow sufficient time for tests. Some tests, such as an induced over voltage test, require 15 min of setup time and last as little as 18 sec. Others, such as taking temperature readings, can last overnight.

AFTER THE TEST:

- Conduct a physical inspection of the transformer, using the following checklist as a guide:
- Transformer grounding positions are correct.
- Paint color is as specified.
- Name plate, cautionary plates, etc. are correct and in an easily readable position.
- Transformer terminals allow for reliable connection and cable support in the field.
- Accessories are in the proper location.
- Gauges and monitors are positioned for readability and accessibility

Alternatives to witness testing. Although manufacturers usually don't charge for testing that doesn't incur unreasonable expenses, you must pay for your inspector's time and travel. If this is prohibitive, you should consider the following less expensive alternatives.

- Company audit.

If you plan to or already work repeatedly with a single manufacturer, conduct a quality audit. Audits, which are standard among major corporations, include an in-depth inspection of the company's facilities and a review of procedures to determine if the manufacturer pays proper attention to all design and manufacturing processes. When you've identified, and the manufacturer has resolved, any issues of concern, you can forego future witness testing or do so only on an as-needed basis.

- Design and production partnership.

Less formal than an audit, this partnership encourages you and the manufacturer to work together throughout the order production testing process. You receive detailed test reports before shipment. Careful examination and discussion between you and the test engineers, or manufacturer representative, can provide the same information as a witness test.

- Similar unit test.

You'll receive results from tests conducted on similar units to provide an early view of your transformer's performance. These reports are available at any time during your transformer's construction life. Getting the transformer you want means effective coordination. Whatever level of product quality review you choose, remember partnering with your transformer manufacturer is key to getting the unit you want. If you change your specification requirements, let the manufacturer know of the changes immediately to minimize the cost later. Lastly, but most importantly, witness testing can provide you a better understanding of your transformer's operation.

SIDEBAR: TESTS YOU CAN WITNESS

All transformers undergo two kinds of industry-standard tests, routine and design, to ensure the transformer will perform as designed. Further optional tests explore the quality of the transformer's construction, assurance, and adherence to standards.

Manufacturers in the United States perform tests in accordance with applicable IEEE and NEMA standards (as approved by ANSI procedures). Overseas customers may require their transformers comply with IEC (International Electrotechnical Commission) specifications. Generally, the manufacturer repeats tests for witnessing for only those you specify. If you have no specific requests, the manufacturer will conduct routine ANSI tests. These include:

- Ratio and phase relation;
- Resistance;
- Excitation loss and current;
- Load loss and impedance;
- Applied voltage; and
- Induced voltage

Design tests, also called type tests, are required only on one of a series of similar or duplicate units. However, you may request the manufacturer perform any of the design tests (usually impulse tests) on any unit. These include:

- Impulse;
- Short circuit;
- Temperature (heat run);
- Insulation power factor;
- Insulation resistance;
- Sound; and
- Partial discharge

HIGH-PERFORMANCE TRANSFORMER OIL PUMPS: WORTH THE INVESTMENT

PlantServices.com

Transformer oil pumps have evolved dramatically over the past several decades. Once considered to be merely a replaceable routine maintenance item, comparable to, say, a valve, pumps are now almost universally recognized as a critical component of "forced-oil-cooled" transformers – a component that requires sophisticated engineering, high-quality construction and systematic preventive maintenance.

When a transformer oil pump performs properly, it ensures maximum cooling to maintain the transformer's peak load capacity. However, impairments to a pump can result in costly breakdowns and potentially catastrophic damage to the transformer. Unfortunately, such impairments are notoriously difficult to detect and prevent in pumps that are designed and/or constructed inadequately.

Transformer oil pump manufacturers in the United States have provided worldwide leadership in addressing these problems by introducing design improvements and innovations such as ultrasonic sensors that monitor the condition of bearings. Major North American utility companies have also driven the development of high-performance transformer oil pumps by requiring thermal, mechanical, sealing, electrical and fluid systems that provide dependable operation.

THE CHALLENGE

Pumping transformer oil is a demanding application. The pump must operate continuously, year after year, pumping high-temperature oil and remaining hermetically sealed in harsh outdoor environments.

One of the most challenging aspects of transformer oil pump design is the fact that the transformer oil also functions as the pump's lubricant. The problem is that transformer oil is selected – not for its lubricating performance – but rather for its ability to function as an insulator to suppress corona and arcing within the transformer, and for its ability to maintain stability and good dielectric properties at high temperature. Highly refined mineral oil works well inside the transformer, but it is a poor lubricant for the ball bearing systems in many types of transformer oil pumps.

THE RISK

Wear of the bearing system and impeller can lead to the release of metal particles into the oil circulating through the pump, cooler and ultimately, the transformer. As a result, the dielectric properties of the oil and insulation can degrade, potentially causing hazardous arcing.

Degradation of the bearing system and impellers, as well as impairments of motor windings, also can cause a reduction in pump flow and discharge pressure, which causes reduced cooling capacity.

Leaking electrical connectors and gasketed surfaces can impair pump performance and allow the ingress of moisture into the oil, as well as oil leaks into the environment.

State-of-the-art pumps mitigate these risks in a number of ways, including improvements to bearing design, ultrasonic monitoring of bearing condition, and high-quality construction. Properly designed new or remanufactured pumps can take advantage of many of these advancements in transformer oil pump technology.

BEARING DESIGN

Of all the design improvements in transformer oil pumps over the past several decades, the single most important one is the replacement of ball bearing systems with bronze sleeve bearings.

As mentioned above, transformer oil provides a poor lubricant for ball bearings. In fact, ball bearings are a viable solution only when lubricated by heavier oil or grease. They fail prematurely when lubricated by lightweight, low-viscosity transformer oil.

Additionally, ball bearing pumps that are not operated continuously will commonly fail as a result of false brinelling of the bearings caused by transformer vibration or slight flow caused by convection.

False brinelling occurs when vibration pushes the lubricant away from a region that it is intended to protect. In a situation when a mostly stationary bearing is subjected only to oscillating or vibrating load, the lubricant may be pushed out of the loaded area.

However, since the bearing is rolling only small distances, there is no action or movement that replaces the displaced lubricant. The resulting wear debris oxidizes to form an abrasive compound, which further accelerates wear.

All U.S. manufacturers, and some foreign suppliers, have discontinued using ball bearings in transformer pump designs. North America's largest manufacturer and remanufacturer of transformer oil pumps, Cardinal Pumps & Exchangers in Salem, Ohio, a division of Unifin International, retrofits all ball bearing pumps with pump-specific bronze sleeve type radial/thrust bearings and hardened steel thrust collars.

The key to the design of thrust and radial bearings for transformer oil applications is large thrust face sleeve bearings for long life and minimum wear. The bearings need to have proper surface finish and precisely positioned grooves to pass the oil and maintain an adequate lubricant film under all conditions.

MONITORING BEARING WEAR

Reliable long-term performance of transformer oil pumps depends not only on the bearing and hydraulic design systems, but also on the ability to proactively detect wear, to ensure effective and energy-efficient cooling performance and to protect the pump and transformer from damage and breakdowns.

A patented ultrasonic bearing wear-monitoring system was developed in by J.W. Harley/TecSonics Inc. (acquired by Cardinal Pumps and Exchangers, Inc.) to overcome the shortcomings of conventional transformer pump bearing wear detection methods based on sound, vibration and oil contamination.

Such methods proved inconsistent and unreliable, and they were useful only after the pump was in an abnormal operating state or on the verge of catastrophic failure.

The ultrasonic bearing wear system, TecSonics, provides advance warning. By tracking data over time, the monitoring system provides rate-of-wear information that enable informed decisions about selective, preventive maintenance, to protect equipment, avoid breakdowns, and optimize maintenance effort and expense.

The principle of operation of the ultrasonic monitoring system is not complicated. Six precision ultrasonic sensors are mounted in both thrust and radial bearings at strategic points, on new pumps or on remanufactured pumps from various manufacturers.

A permanently mounted piezoelectric transducer emits a high-frequency sound wave, and precisely measures the echo time to determine the distance between the sensor and the bearing surface, to an accuracy of 0.0002 inches. Measurements are compared to baseline readings to determine if any bearing wear has occurred.

The temperature-compensated readings can be taken while the pump is under any operating condition, without disassembling the pump, whether the pump is operating or not. The sensors do not affect the performance of the pump. In addition to the ultrasonic system for monitoring bearing wear, it also is useful to have a shaft rotation sight plug to facilitate checking for proper shaft/impeller rotation.

QUALITY CONSTRUCTION

A third consideration, beyond the design and monitoring of the bearing system, is the overall quality of construction, both in terms of the quality of materials and the quality of manufacturing.

Pumps should be constructed of rugged cast iron material for the pump castings (casings, motor enclosures and impellers) to provide long life in the field. To protect the exterior surfaces from corrosion, high-performance/high-quality coatings (primer and top coats) should be applied.

All sleeve bearing pumps should have the bearing journals and thrust surfaces ground between centers to ensure alignment and surface finish. All pump shaft, impeller and motor assemblies should be dynamically balanced to assure long-term vibration-free operation.

Durable electric supply power cords also help to ensure reliable transformer pump performance. They should be capable of withstanding ultraviolet rays, oil, water and extreme weather conditions.

THE ECONOMICS OF TRANSFORMER OIL PUMP INVESTMENT

Investment in high-quality new and remanufactured transformer oil pumps has a high economic return. A good pump will typically cost much less than 1 percent of the cost of the transformer that it supports, and yet it provides long-term insurance against breakdown, damage or failure of the transformer. And as all owners of large critical transformers will attest, a failure or major outage of this equipment can cause severe upheaval to the wellbeing of their electrical power distribution system.

High-quality pumps also pay for themselves in lowered maintenance and replacement costs. Properly designed sleeve bearing pumps reliably perform 15+ years - more than three to four times the typical useful life of ball bearing pumps. In addition, pumps with ultrasonic monitoring systems are less costly to operate because preventative maintenance can be efficiently planned.

INFRARED DIAGNOSTICS ON PADMOUNT TRANSFORMER ELBOWS

Jeff Sullivan, Mississippi Power Company, Hattiesburg, MS

ABSTRACT

Mississippi Power Company has been a leader and trendsetter in finding new and better ways to increase customer satisfaction. For this reason, we implemented a program of infrared thermographic inspection using infrared thermal imaging cameras, and all the electrical equipment in our facilities, including all of our 750 KVA to 2500 KVA padmount transformers, one of which had failed disastrously.

During a survey of these transformers, I detected thermal problems with more than 30% of the 400 scanned, all associated with the high side elbow connection. Further investigation related the failure mechanisms to improper installation techniques during both the original installation and the routine preventive-maintenance replacement of the elbows.

Using newer improved equipment and holding training classes on proper installation and removal of this equipment, we reduced the occurrence rate of these anomalies from 30% to less than 2%. Our management authorized the purchase of an additional infrared camera, also known as a thermal imaging camera.

This paper describes the program and the findings, explains the diagnostics and illustrates the contrast between properly and improperly installed equipment.

1. INTRODUCTION

Mississippi Power Company began doing infrared scans, using an infrared thermal imaging camera in 1994, as a support service to our industrial and commercial customers. Over the past several years, we have come to realize the value of using infrared thermal imaging cameras to find and solve problems for our customers as well as for ourselves. Being proactive, our department added more people to keep up with the increased needs of our customers and to provide the best reliable service to our customers. We did this by purchasing additional infrared thermal imaging cameras and increasing the scope of work to include infrared scans of our substations, feeders and all of our padmount transformers rated from 750KVA up to 2500KVA. We now have three infrared thermal imaging cameras in Mississippi Power Company.

Padmount transformers are transformers that are sealed in metal containers and filled with oil. They are used to step up or down the output voltages depending on customer needs. They range in size form 50KVA to 2500KVA and vary in shape. The main reason for using padmount transformers is that they offer a wide selection of load capacity in modular, encapsulated form. Other reasons include esthetics and safety; in designated areas such as in subdivisions, encapsulated padmount transformers are safer to operate and can be placed underground, where they are out of sight and impervious to falling trees and other hazards.

The elbow problems that we found and identified with the use of the Infrared camera were put into three categories for the purpose of identifying, tracking and repairing the problems. They are contact, probe and crimp problems. With the use of the infrared camera and through training we have reduced the problems from 30% to less than 2%.

2. CLASSIFICATION OF PROBLEMS

My job consists of doing infrared scans for customers, on padmount transformers and on our feeders. Since additional personnel were assigned to the department, I have been able to concentrate on padmount transformers more than was possible in the past. I have used this opportunity to track and record the data from my findings. As it turned out, I discovered that we have a serious ongoing problem with padmount transformer elbows. With 400 transformers scanned, I found that 30% of the padmount transformers had an elbow problem. With experience gained from working in electrical substations for 12 years as an electrician, and from other sources, I was able to determine what caused the problems and how to correct them. After reviewing them, I classified them into three categories, contacts, probes and crimps.

The first category is the contact problem. This occurs when the female bushing is replaced after a failure. If grease is applied incorrectly on the stud of the internal winding of the transformer, when the female bushing is threaded onto the stud, it forces the grease into the contacts of the female bushing. When the transformer is energized, the grease heats up, turning into a liquid and acting like a hydraulic pump, forcing the probe backwards. This action causes the contacts to arc and eventually burn up. Similar heating will occur if the elbow is not properly seated when installed. Fig. 1 illustrates two examples of an elbow that is not properly seated due to a mechanical error or grease being applied improperly.

The second problem category is the loose probe; related to the method of removing the elbow from the transformer after the unit had been in service. When an elbow has been installed for a period of time, it creates a vacuum or suction due to the load of the transformer. To remove the elbow from the transformer, it has to be twisted back and forth several times to break the vacuum or suction it had created due to load changes. Each time the elbow is twisted counterclockwise, it causes the probe to loosen from the threaded crimp and eventually causes the probe to burn up. Through proper training and the use of a ring stick with a slide weight on it, the elbows could be removed by one person and installed properly, therefore practically eliminating this problem. Fig. 2 illustrates two examples of loose probes.

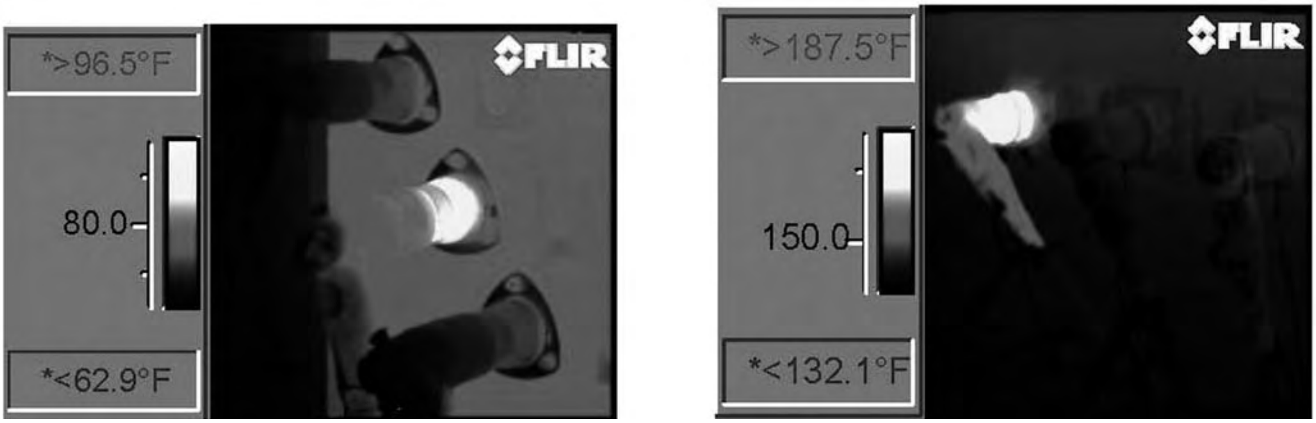


Figure 1. Two examples of heating on a padmount transformer due to improper elbow installation that will lead to contact damage

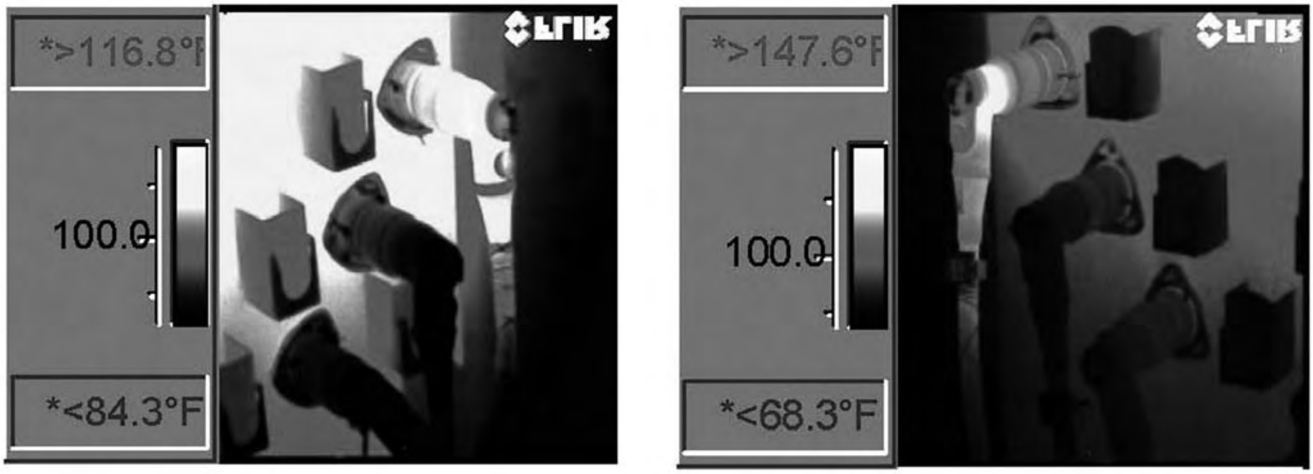


Figure 2. Two examples of heating on a padmount transformer due to loose probes

The third problem category concerns the crimp on the underground dip wire. There are two different problems associated with the crimp. The first occurs when the wrong size crimp is used. The second occurs as a result of an improperly executed crimp connection. Either one will cause overheating that will lead to a failure. Fig. 3 is an example of the result of a bad crimp connection.

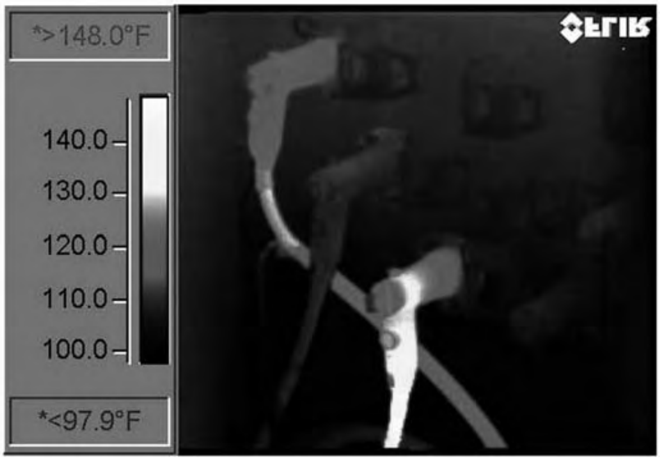


Figure 3. Overheating of an elbow caused by a bad crimp connection

3. CONCLUSIONS AND COST AVOIDANCE SUMMARY

Through the use of the infrared camera, we have found and solved problems that would have been disastrous if they had not been detected in time. One of the best results of doing infrared scans is that it has allowed Mississippi Power Company to greatly improve customer relations in dependability and reliability. Unscheduled outages are a big problem to a company like ours, and by using the infrared camera in routine predictive maintenance we perform, we have greatly reduced our customers' outages.

If a padmount transformer elbow were to fail for one of our larger customers, the average time to get the customer back to 100% production would be about four hours of outage time. Several of our customers estimate their losses to be about $1,000 a minute when they are out of power due to an elbow failure problem. This computes to a $240,000 customer loss for an outage.

By using the infrared camera to find the problems, identify and fix the problems on a controlled outage situation, Mississippi Power Company and our customers have shared in the rewards. The elbow problems found on padmount transformers were found, identified and fixed, reducing the problem by 28% through proper training of everyone involved with installation and removal of padmount transformer elbows. This saved Mississippi Power Company from loss of revenue, having to pay overtime and from destruction of expensive equipment, thereby improving customer relations and satisfaction. Also, the customer benefited greatly from Mississippi Power Company being proactive by offering infrared services to them. The bottom line is that the infrared camera is a win/win for everyone. It is one of the best purchases a company can make. Not having an Infrared camera in our business would be like going back into the Stone Age.

HOW INFRARED THERMOGRAPHY HELPS SOUTHERN CALIFORNIA EDISON IMPROVE GRID RELIABILITY

Bob Turnbull and Steve McConnell, Southern California Edison, Alhambra, CA

ABSTRACT

The Infrared Thermography Inspection program at Southern California Edison has been fully integrated into its predictive maintenance protocol at all its facilities. This paper will provide an overview of the program.

Overviews of the physical facility structure and the staff organizational chart will be provided. Day-to-day inspection procedures, reporting mechanisms and follow-up protocol will be reviewed. Examples of critical findings and their repair disposition will be reviewed. Personnel training and certification programs will be discussed.

The paper will conclude with a review of the company's plans for marrying their infrared inspection program with currently planned facility expansion.

1. INTRODUCTION: A BRIEF OVERVIEW OF SOUTHERN CALIFORNIA EDISON

SoCal Edison services more than 4.1 million customers in a 50,000 square mile service territory in Southern California with a peak demand of 21GVA. Our 80 GVA installed capacity is delivered through 858 substations in which the equipment complement includes:

- 900 substation busses
- 3,300 power transformers
- 10,800 circuit breakers rated from 500 2,400 Volts

2. OVERVIEW OF THE SUBSTATION CONSTRUCTION AND MAINTENANCE DEPARTMENT

Figure 1 is a structural chart of our organization headed by Mr. Bob Turnbull, Technical Supervisor of Substation Construction and Maintenance Support Services. The heart of our controlled PdM program is the computer-based PassPort, which is the name for our Work Management System.

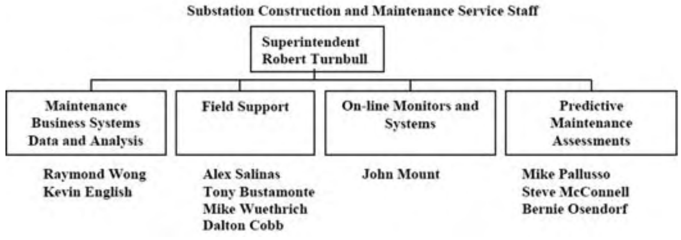


Figure 1. Our organization chart

Maintenance Business Systems data and analysis personnel provide:

- Substation Construction and Maintenance web-site technical lead and development
- PassPort Work Management System maintenance data
- Real-time KPI (key performance indicators) status
- Transporting and management of data
- Data communications systems architecture and database structure

Technical Field Support personnel provide:

- Installation, operation and maintenance recommendations, equipment failure analysis and reports and on-line oil filtering and Morgan Schaffer monitoring for transformers, reactors LTCs (load tap changers) and oil-filled CT/PTs (current transformers/voltage transformers).
- Installation, operation and maintenance recommendations for power circuit breakers and GIS (gas insulating systems).
- Maintenance cost factors provided by the equipment specification team member
- Capital replacement strategy provided by the transformer resource management team member
- Equipment problem resolution and supplier performance tracking by the ABB (Asea-Brown-Boveri) circuit breaker team member
- Resource manual, SF6 residual credit and new gas processing equipment provided by the SF-6 sulfur hexafluoride insulating gas) gas resources team member

On-line Monitoring personnel provide:

- On-line monitor links to our PassPort Work Management System
- Development of response time recorder replacement
- On-line equipment monitoring technical lead analysis and on-line monitor data

3. OUR PREDICTIVE MAINTENANCE ASSESSMENT PROGRAM

The mission of our PdM assessment (PMA) program is to improve and optimize grid reliability through the deployment of a multidisciplinary diagnostic program of equipment monitoring. The elements of this program are:

- PdM technical lead
- Maintenance initiatives
- Infrared diagnostics

- Acoustical diagnostics
- Vibration analysis
- Technical reporting
- Technical recommendations

With all these elements in place, and by means of our Predictive Maintenance Assessment (PMA) reports, we have consistently demonstrated and documented failure avoidance and cost avoidance. Our Infrared Thermography Inspection program in particular has been most dramatic in this regard, as shall be demonstrated by examples given later in this paper. As a result, we have convinced Management that our program should be ongoing and continuously expanded. This management "buy-in" is crucial to any program of this kind.

The importance of "selling" the program to our own team members as well as to Management cannot be emphasized enough. While Management's major concerns involve meeting business goals and maintaining profitability, the goals of our team members revolve more around job satisfaction, recognition of contribution by Management and personal enrichment and advancement. Working with one of the most modern and powerful technologies, such as infrared thermography, goes a long way toward achieving these goals. Nothing works like success, and we have been most successful in this area.

Field personnel also benefit by the success of the program. Frequent systematic inspections, meaningful findings and timely maintenance and repair optimize personnel and facility safety, minimize down time and enhance the job satisfaction of field operating personnel.

Most critical to our program is emphasizing the concept of a "team effort". Effective communications among team members is essential. The need to "close the loop" on any finding must remain foremost in the minds of all team members.

4. THE PMA PROCESS – CLOSING THE LOOP

The PMA process begins with regularly scheduled inspections at locations designated by the program managers and supplemented, on occasion, by special requests from the field. The technical specialists, such as the IR thermographers, perform the station inspections and determine the criticality of each finding, assigning a severity level to each detected abnormality. These levels, in the case of infrared thermography, are determined, for the most part, by the maximum detected temperature rise over a predetermined reference temperature, with Level 1 being the most critical and requiring the most immediate attention. The severity levels are defined as follows:

CRITICAL PROBLEM-PRIORITY LEVEL 1

Any problem that is identified as a safety hazard, or an immediate threat to grid reliability.

Identified through the use of diagnostic analysis and inspections.

ACTION REQUIRED: REPAIR IMMEDIATELY.

Foreman/electrician to make decision and take immediate corrective action to relieve the problem. Notify superintendent and program manager as soon as possible.

Note: the corrective action may be in the form of switching to relieve load, jumper out a disconnect switch, repair or remove equipment from service, etc.

SERIOUS PROBLEM-PRIORITY LEVEL 2

A problem that has the potential to develop into a hazardous condition and effect grid reliability. Identified through the use of diagnostic analysis and inspections.

ACTION REQUIRED: REPAIR IN THE IMMEDIATE FUTURE.

Foreman/technical specialist shall periodically monitor until repaired. Technical specialist notifies supervision and submits a written report. Foreman/program manager to establish priorities and schedule at monthly foremen's planning meeting.

Note: this type of problem will progressively worsen

INTERMEDIATE PROBLEM-PRIORITY LEVEL 3

A problem that is identified as no immediate threat to personnel or grid reliability.

Identified through the use of diagnostic analysis and inspections.

ACTION REQUIRED: SCHEDULE THE REPAIR.

Foreman/program manager to establish priorities and schedule at monthly foremen's planning meetings.

Note: this type of problem is less likely to be immediately detrimental to personnel or to the grid.

MINOR PROBLEM-PRIORITY LEVEL 4

A problem that is identified as requiring routine attention or maintenance. Little probability of physical damage. Identified through the use of diagnostic analysis and inspections.

ACTION REQUIRED: REPAIR AS PART OF REGULAR MAINTENANCE.

Foreman to establish priorities and complete repairs as time permits.

Note: this type of problem is very unlikely to be detrimental to personnel or to the grid.

The technical specialist then inputs the data into the WMS for the creation of field reports and maintenance repair work orders and the WMS generates the formal reports and work orders. The technical specialist also notifies the field maintenance crews directly when there are any severity Level 1 abnormalities detected.

Acting on the severity Level I abnormality report, the appropriate foreman generates and releases validation sheets directing repair crew (electricians) to perform the indicated repairs. The crew completes and documents the repairs, the site is reinspected and the foreman closes the work order and enters the repair data in the WMS.

All PMA findings are discussed during regularly scheduled monthly workload meetings attended by team personnel from all groups. Cost avoidance reports generated for all Level 1 abnormalities and repairs are discussed at these meetings.

Information for reporting trends to Management is derived by querying the WMS database. In this way reports are prepared from the PMA process for assuring continuing Management support.

1. EXAMPLES OF FINDINGS USING IR THERMOGRAPHY

We are currently using an Inframatrics model PM 295 uncooled-microbolometer based infrared camera. We employ three (3) Level II certified infrared thermographers. A fourth thermographer is currently in training.

We inspect a wide variety of operating equipment in our substations, including transformers, circuit breakers, bushings, disconnects, fuses, roto-switches, secondary current terminations, potheads, station batteries and relays. The following are illustrations of some of the abnormalities detected.

1. HOT BATTERY TERMINAL

A hot connection was detected on a battery terminal at our Anita Substation as illustrated in Figure 2. A rise of greater than 1°C is considered extraordinary in this type of equipment and required immediate attention.

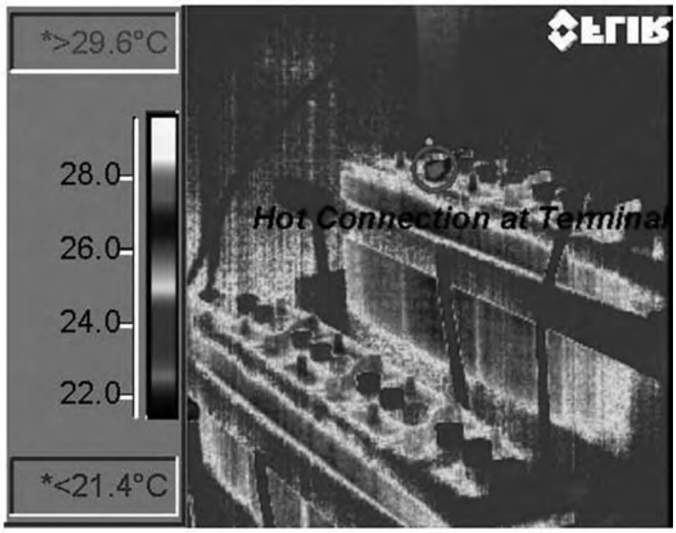


Figure 2 Hot connection at battery terminal (top)

2. OVERHEATED FAN CONTROL CIRCUIT TERMINALS

At our San Bernadino Substation, the 1AA bank fan control circuit exhibited 2 overheated terminals, as shown in the thermogram of Figure 3. The terminal at the left exhibited a rise of 135°C and the one at the right exhibited a rise of 153.6°C.

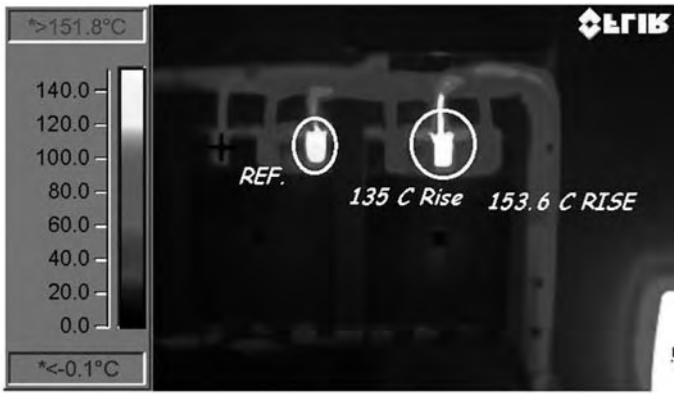


Figure 3. Fan bank control circuit with 2 overheated terminals

3. NO OIL FLOWING THROUGH TRANSFORMER RADIATOR

The thermogram of Figure 4., taken of a transformer bank at our Center Substation, illustrates the effect of the oil flow being shut off from the radiator at the right, resulting in a ΔT of greater than 20°C.

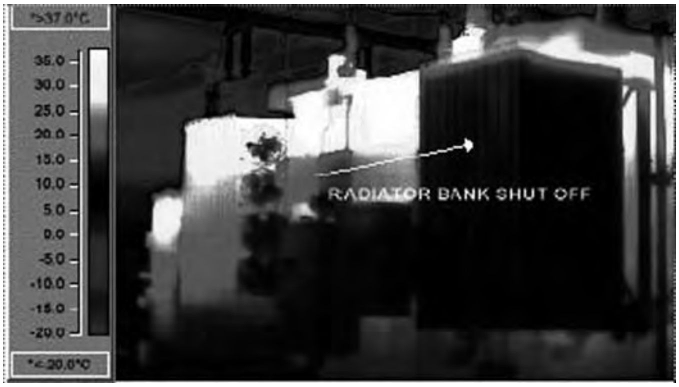


Figure 4. The effect of oil being shut off from the radiator at the right

4. OVERHEATED TAP CHANGER

The tap changer shown at the center of the thermogram of Figure 5, taken at our Elsinore Substation, was measured to be more than 7°C hotter than the main tank (shown at the left).

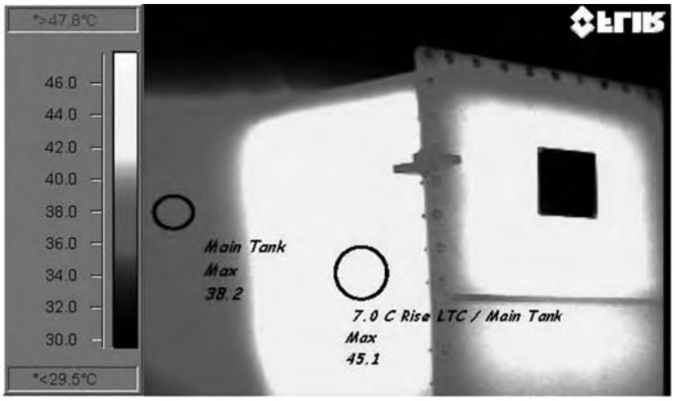


Figure 5. Tap changer (center) measured to be more than 7°C hotter than the main tank (left)

5. HOT BUSHING ROD

A hot bushing rod, detected at our Santiago Substation, Is shown in the thermogram of Figure 6. This bushing rod (lower center) had a measured temperature of 93.7°C, which was more than 60°C hotter than the reference point shown at the upper left.

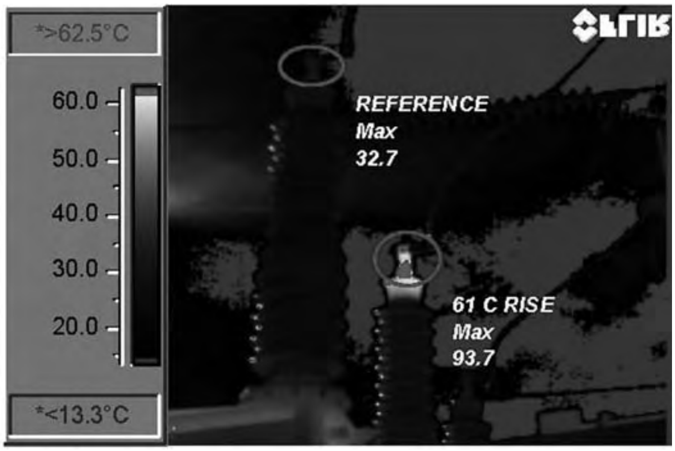


Figure 6. Hot bushing rod (center) measured to be more than 60°C hotter than reference bushing

6. LOW OIL LEVEL INDICATION

A measured temperature difference of greater than 10°C resulted from the low oil level in the radiator at the left of the thermogram of Figure 7, taken at our Sierra Madre Substation. The radiator at the right, with normal oil flow is at a measured temperature of 31.6°C compared to the 18.9°C reading taken on the left-hand bank.

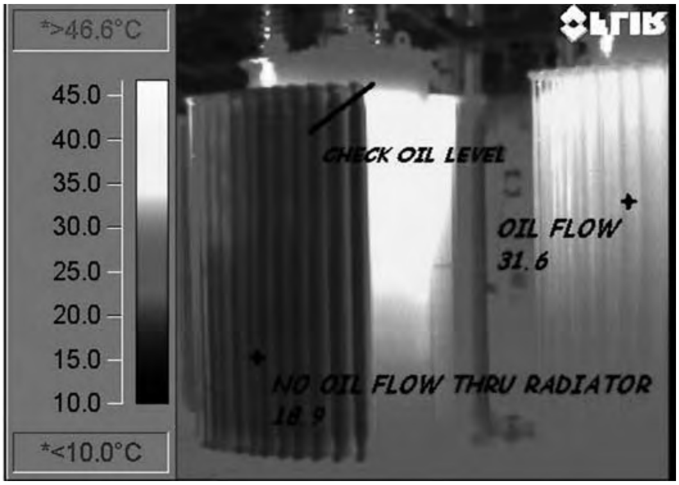


Figure 7. The low oil level in the left hand transformer bank results in no oil flow through the radiator

7. HOT FUSE CLIPS

Several hot fuse clips appeared on the thermogram of Figure 8., taken on the main DC fuse panel at our Anita Substation. As indicated in the thermogram, the clips marked from left to right exhibited ΔTs of 7.2°C, 4.6°C and 3.9°C respectively above the 28.0°C reference.

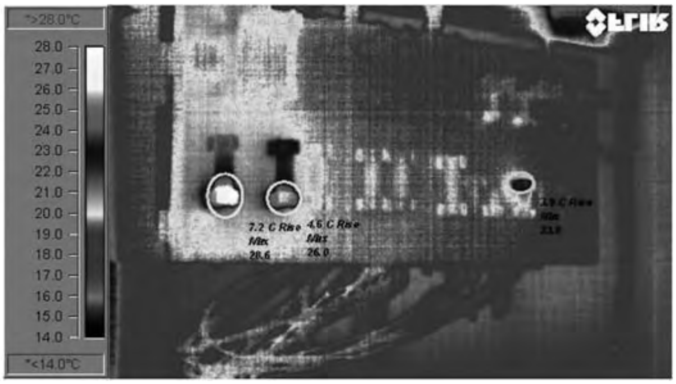


Figure 8. Hot fuse the clips exhibited ΔTs of 7.2°C, 4.6°C and 3.9°C respectively above the 28.0°C reference

2. SUMMARY: WHAT WE HAVE DONE TO DATE AND WHERE WE GO FROM HERE

1. COST AVOIDANCE BENEFITS

The "bottom line" in any PdM program resides in the cost avoidance results. From 1998 to the present we have inspected 450 substations with our multidisciplinary assessment program. Of the more than 3000 real anomalies detected and corrected over this period, more than 1500 (about 50%) were detected by means of infrared thermography. Table 2 illustrates the results by severity criteria over this testing period. Estimated savings in cost avoidance are in the millions of dollars per year from the IR thermography program alone, far exceeding the cost of the equipment and the training of our thermographers. Clearly, in terms of "bang for the buck", IR comes out way ahead.

Table 2. Anomalies detected from 1998 to the present in 450 substations inspected

Severity Level Classification	Total Anomalies Found	Total Anomalies Found by Infrared Thermography
Level I	299	159
Level II	1529	849
Level III	1449	503
Total	**3277**	**1508**

2. WHERE WE GO FROM HERE?

It has become apparent that the combination of incorporating infrared imaging cameras into our PMA, and meticulously training our personnel in their operation has paid off in terms of avoided down time, avoided repair costs and enhanced safety for our operating personnel and equipment.

Our company has planned extensive expansion of our substation network over the next few years, and our Management has come to recognize the impact of our Infrared Thermography Inspection program on safety and profitability. To keep pace with our planned expansion, we are projecting the addition of more thermal imaging systems and the training and assignment of another thermographer in the immediate future. Our future plans also call for training more field electricians to become infrared thermographers.

THE VIBRATING TRANSFORMER

Fluke

PROBLEM DESCRIPTION

This case history comes from an electrical contractor. Several of this contractor's clients operate large commercial buildings. One of these clients asked for help with a large transformer that had suddenly started vibrating and making a loud buzzing sound. The client was concerned that the transformer was ready to fail and he would be faced with an expensive replacement. The contractor dispatched an engineer at once.

When the engineer arrived at the plant, he took out his notebook and his Fluke 43B. He then made the following notes and one line diagram:

Transformer size: 1500 kVA

Transformer configuration: Delta/wye, 480 V 3-phase secondary

Secondary load: Motors, lighting, and office machines for a large office building

[Note: The client says the transformer is lightly loaded because many of the tenants have recently moved to a new location.]

MEASUREMENT DATA

The engineer recorded the following data using the Fluke 43B:

Secondary voltage total harmonic distortion: 2.7%
Secondary voltage balance: within 1%
Secondary current: 57 A rms
Secondary current spectrum:
Fundamental 55 A
2nd harmonic 1.6 A
3rd harmonic 2.5 A
4th harmonic 0.7 A
5th harmonic 2.4 A
6th harmonic 0.4 A
7th harmonic 4.0 A

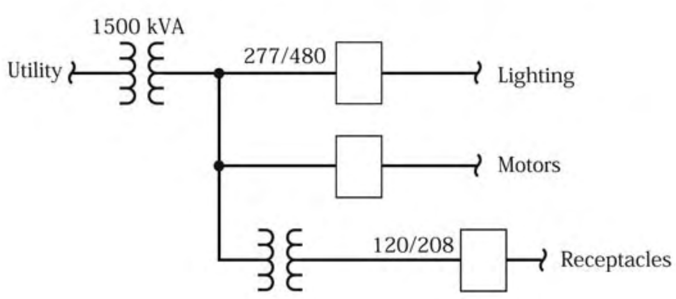


Fig. 1 Partial one-line diagram of large commercial building

THEORY AND ANALYSIS

The voltage measurements do not show anything abnormal.

The voltage total harmonic distortion is well within the maximum allowable value of 5%. Voltage balance between phases also looks good. The secondary current of 57 A indicates the client was correct in stating the transformer was lightly loaded. No overheating was noted.

When a transformer is in trouble, this contractor's engineers always use a Fluke 43B to measure the harmonic spectrum of the secondary current. The spectrum acts like a fingerprint, indicating the types of loads present. In this case, the presence of the 3rd harmonic shows that part of the load consists of single-phase devices (e.g., fluorescent lighting ballasts) connected phase to neutral. In the data, the amount of the 3rd harmonic is relatively low and appears to be normal.

The 5th and 7th harmonics indicate that part of the load is a large 3-phase device with semiconductor rectifiers in the input circuit. The most common example would be an adjustable speed motor drive operating a fan or pump. When a 3-phase motor drive is operating normally, the input current waveforms are symmetrical about zero. That is, the positive going portion of the waveform looks like the mirror image of the negative portion. When all semiconductors are operating normally, the input currents have no DC offset and only odd harmonics are present.

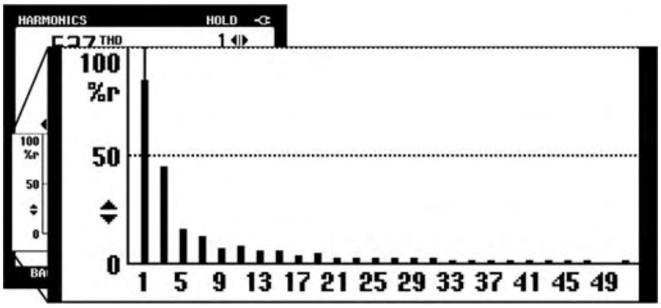


Fig. 2 Example of a normal AC current spectrum with all odd harmonics

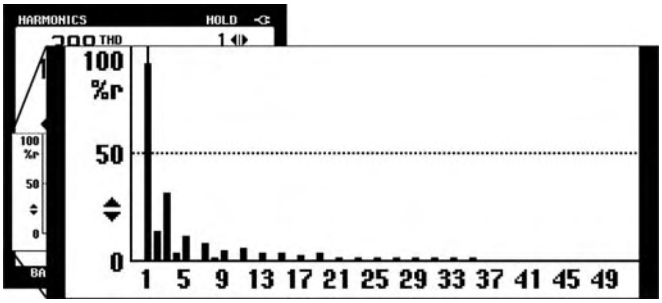


Fig. 3 Example of an abnormal current spectrum with both odd and even harmonics

The engineer noted that the spectrum had even harmonics (2nd, 4th, and 6th). These abnormal harmonics indicate the presence of DC current in the transformer secondary winding. Compare the example spectrums in Fig. 2 and Fig. 3.

Unfortunately, DC current tends to saturate the transformer core at the peak of one half of the AC waveform. When the core goes in and out of saturation, it will vibrate and make a loud buzzing noise.

The engineer suspected that the plant load contained a large motor drive and that one of the input semiconductors had failed to open. If one semiconductor is open, the circuit on that phase becomes a half-wave rectifier — it produces DC current. The trick here is that the motor drive will continue to operate at low speed because the other two phases are operating normally.

SOLUTION

The engineer asked if any large motor drives were operating. The plant manager confirmed that one large drive was operating a ventilation fan.

The engineer instructed the plant manager to have the drive shut off. When the drive was shut off, the transformer immediately stopped vibrating.

TRANSFORMER/LINE LOSS CALCULATIONS

Schneider Electric

OVERVIEW

Loss Compensation is used when a meter's actual location is different from the electrical location where change of ownership occurs; for example, where meters are connected on the low-voltage side of power transformers when the ownership change occurs on the high-side of the transformer. This physical separation between meter and actual billing point results in measurable losses. Compensating for this loss - Loss Compensation - is the means of correcting this meter reading.

Losses may be added to or subtracted from the meter registration.

Meters are usually installed on the low-voltage side of a transformer because it is more cost-effective. There are also cases where change of ownership may occur halfway along a transmission line where it is impractical to install a meter. In this case, power metering must again be compensated.

LINE LOSS AND TRANSFORMER LOSS AFTER THE PCC

The PCC (Point of Common Coupling) is the interchange point between the distribution grid and a particular customer. Unlike losses that occur within a transmission/distribution network, which cannot be allocated to a single customer and must be rolled into the per-unit cost of electricity, losses that occur after the PCC can be measured and allocated accordingly.

Element	Definition
$\frac{r}{l}$	Per unit length resistance
$\frac{x}{l}$	Per unit length reactance
L	Total length in units
R	Resistive component
Z	Impedance
P_{loss}	Active power loss
X	Reactive component
Q_{loss}	Reactive power loss

CAUSES OF LINE LOSS

Line Losses are a result of passing current through an imperfect conductor such as copper. The conducting material has characteristic impedance that produce, a voltage drop along the line proportional to the current flow. The total line impedance can be determined from the elements on the presious chart:

The resistive component (R) of the impedance (Z) contributes to active power losses (Ploss), while the reactive component (X) contributes to reactive power losses (Qloss).

The line-losses can be calculated based on the measured current load as:

$$LLW = P_{loss} = I \times \left(I \times \frac{r}{l} \times L\right) = I^2 \times R \qquad (1)$$

$$LLV = Q_{loss} = I \times \left(I \times \frac{x}{l} \times L\right) = I^2 \times X \qquad (2)$$

For a 3-phase system, the losses for each phase are calculated separately according to the measured current as:

$$P_{loss-tot} = (P_{loss-a} + P_{loss-b} + P_{loss-c}) = (I_a^{\ 2} \times R_a + I_b^{\ 2} \times R_b + I_c^{\ 2} \times R_c) \qquad (3)$$

$$Q_{loss-tot} = (Q_{loss-a} + Q_{loss-b} + Q_{loss-c}) = (I_a^{\ 2} \times X_a + I_b^{\ 2} \times X_b + I_c^{\ 2} \times X_c) \qquad (4)$$

If we assume that the per-phase impedance is similar and use the average impedance, the equation simplifies to:

$$LLW = P_{loss-avg} = \frac{(I_a^{\ 2} + I_b^{\ 2} + I_c^{\ 2})}{3} \times R = I^2_{avg} \times R \qquad (5)$$

$$LLV = Q_{loss-avg} = \frac{(I_a^{\ 2} + I_b^{\ 2} + I_c^{\ 2})}{3} \times X = I^2_{avg} \times X \qquad (6)$$

CAUSES OF TRANSFORMER LOSS

Power transformer losses are a combination of the power dissipated by the core's magnetizing inductance (Iron loss) and the winding's impedance (Copper loss).

Iron losses are a function of the applied voltage and are often referred to as "noload losses" - they are induced even when there is no load current. Copper losses are a function of the winding current and are often referred to as "load losses".

These losses are calculated for any operating condition if a few parameters of the power transformer are known. The transformer manufacturer commonly provides this information on the transformer test sheet:

- rated total kVA of the power transformer (VATXtest).
- rated voltage of the power transformer (VTXtest).

- No-load test watts (LWFeTXtest) - the active power consumed by the transformer's core at the rated voltage with no load current (open circuit test).
- Full-load test watts (LWCuTXtest) - the active power consumed by the transformer's windings at full load current for rated kVA (short circuit test).
- %Excitation current - ratio of No-load test current (at rated voltage) to full load current.
- %Impedance - ratio of Full-load test voltage (at rated current) to rated voltage.

The No-Load and Full-Load VAR losses (LVFeTXtest and LVCuTXtest) may not be provided, but are calculated from the above data.

$$LVFe_{TXtest} = \sqrt{\left(VA_{TXtest} \times \frac{\%Excitation}{100}\right)^2 - (LWFe_{TXtest})^2}$$

$$LVCu_{TXtest} = \sqrt{\left(VA_{TXtest} \times \frac{\%Impedance}{100}\right)^2 - (LWCu_{TXtest})^2}$$

To determine the actual transformer losses, the test losses must be scaled for use at the actual operating voltage and current.

$$LWFe = LWFe_{TXtest} \times \left(\frac{V_{actual}}{V_{TXtest}}\right)^2 \quad (9) \qquad LVFe = LVFe_{TXtest} \times \left(\frac{V_{actual}}{V_{TXtest}}\right)^4 \quad (11)$$

$$LWCu = LWCu_{TXtest} \times \left(\frac{I_{actual}}{I_{TXtest}}\right)^2 \quad (10) \qquad LVCu = LVCu_{TXtest} \times \left(\frac{I_{actual}}{I_{TXtest}}\right)^2 \quad (12)$$

LOSS COMPENSATION IN ION METERS

ION meters that support loss compensation in their default framework are the ION8300/ION8400/ION8500 and the ION7550 and ION7650 meters. For information about Loss Compensation in the ION7700 and ION7300 series, please contact Schneider Electric.

The meters have the following Transformer and Line Loss Compensation features:

- Compensation performed on 1-second total power (kW total, kVAR total, and kVA total).
- Unbalanced loads are handled accurately (except in the case of line-loss of neutral conductor in a 4-Wye system).
- Losses may be added or subtracted.
- Compensation works in all four power quadrants.
- Compensation is available in TEST mode. Support for compensation on singlephase test sets is also available in TEST mode.
- Compensation works correctly when all revenue parameters are reported in secondary units (meter units).

By default, the ION8300/ION8400/ION8500 and the ION7550 and ION7650 meters come configured to provide the following compensated registers:

For Total kW, Total kVAR, and Total kVA quantities:

- Real-time power
- Demand: Thermal and Block
- Calibration Pulsers
- Min/Max

For Total kWh, Total kVARh, and Total kVAh quantities:

- Energy
- Interval Energy
- Energy in Test Mode
- Energy for each TOU rate

The ION8300/ION8400/ION8500 and the ION7550 and ION7650 offer two possible loss calculation methods. One must be selected when Loss Compensation is enabled:

- Test Sheet (Method 1)
- %Loss Constants (Method 2)

Both methods are based on the same calculations and produce identical results if the correct input parameters are programmed into the meter. The difference between these methods is in the type of parameters required to perform the loss calculations.

To simplify verification in Method 2, the user is required to calculate the parameters in advance.

CAUTION

Due to the variation in installations, advanced knowledge of power systems and connection methods is required before transformer loss compensation can be properly implemented. Data parameters should only be programmed by qualified personnel that have appropriate training and experience with Transformer Loss Compensation calculations.

Power Transformer Wiring (metered side)	**ION8300/ION8400/ ION8500 Volts Mode**	**ION7550, ION7650 Meters Volts Mode**
3-Wire Closed Delta	35S	Delta
4-Wire WYE (3 element)	9S	4-Wire WYE
4-Wire WYE (2½ element)*	36S	3-Wire WYE
3-Wire WYE	9S	3-Wire WYE

* V2 values are only accurate for balanced loads.

SUPPORTED TLC CONFIGURATIONS

When compensation is enabled, the meter calculates transformer and line loss based on a set of input parameters. These parameters determine whether the meter adds or subtracts the losses from the measured power. Compensation can be enabled using either the Vista component of ION Enterprise or ION Setup.

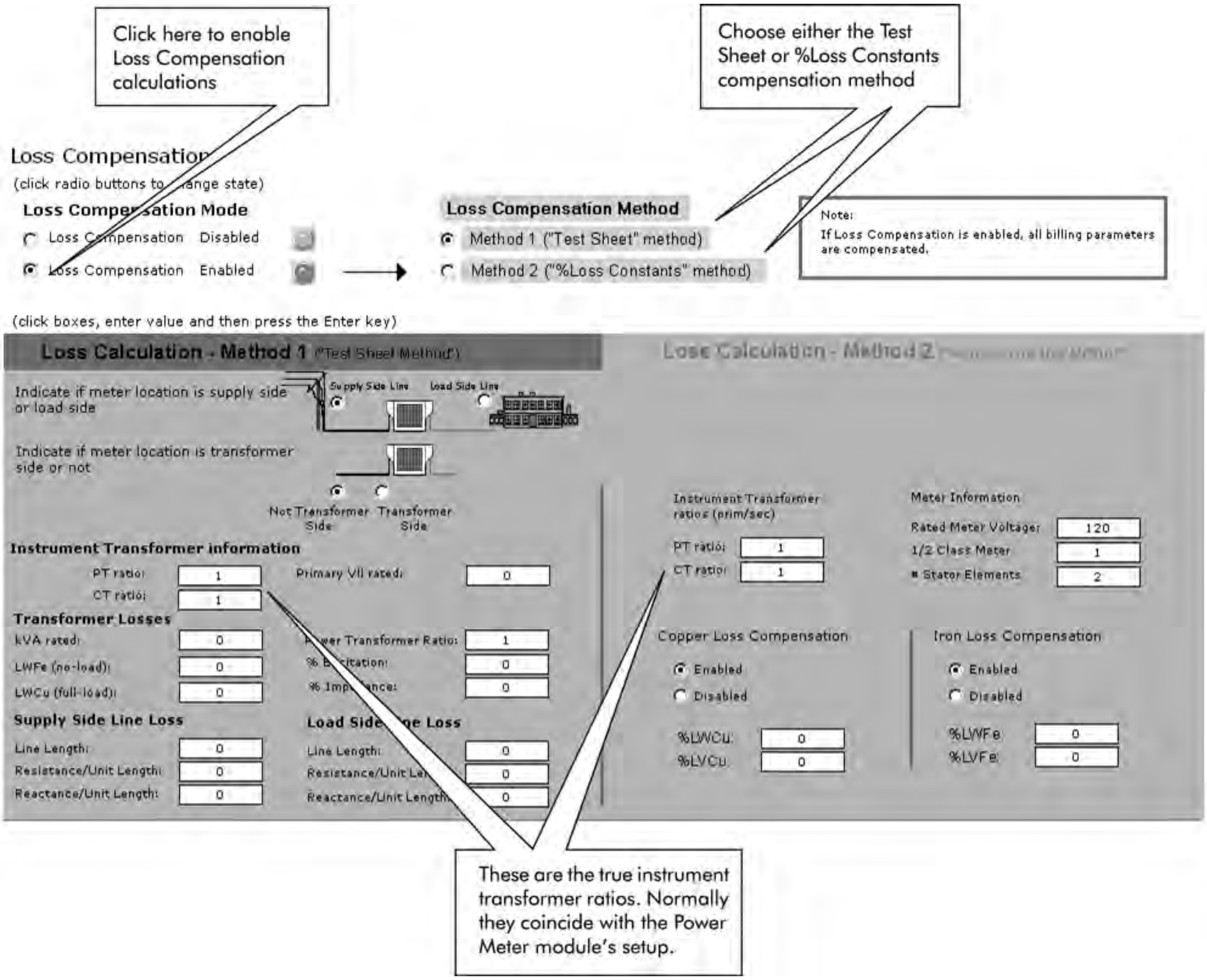
CONFIGURING LOSS COMPENSATION USING VISTA

Click the Loss Compensation button in the Revenue screen to access the Loss

Compensation screen:

1. Launch Vista.
2. In the User Diagram screen that appears, click the Revenue button.

3. Click the Loss Compensation button. The following window appears (the screen for ION8300/ION8400/ION8500 Loss Compensation is shown below):


Click here to enable Loss Compensation calculations

Choose either the Test Sheet or %Loss Constants compensation method

Loss Compensation
(click radio buttons to change state)

Loss Compensation Mode

○ Loss Compensation Disabled
● Loss Compensation Enabled

Loss Compensation Method

● Method 1 ("Test Sheet" method)
○ Method 2 ("%Loss Constants" method)

Note:
If Loss Compensation is enabled, all billing parameters are compensated.

(click boxes, enter value and then press the Enter key)

Loss Calculation - Method 1 ("Test Sheet Method")

Indicate if meter location is supply side or load side
● Supply Side Line ○ Load Side Line

Indicate if meter location is transformer side or not
● Not Transformer Side ○ Transformer Side

Instrument Transformer information
PT ratio: 1
CT ratio: 1
Primary Vll rated: 0

Transformer Losses
kVA rated: 0
LWFe (no-load): 0
LWCu (full-load): 0
Power Transformer Ratio: 1
% Excitation: 0
% Impedance: 0

Supply Side Line Loss
Line Length: 0
Resistance/Unit Length: 0
Reactance/Unit Length: 0

Load Side Line Loss
Line Length: 0
Resistance/Unit Length: 0
Reactance/Unit Length: 0

Loss Calculation - Method 2

Instrument Transformer ratios (prim/sec)
PT ratio: 1
CT ratio: 1

Meter Information
Rated Meter Voltage: 120
1/2 Class Meter: 1
Stator Elements: 2

Copper Loss Compensation
● Enabled
○ Disabled
%LWCu: 0
%LVCu: 0

Iron Loss Compensation
● Enabled
○ Disabled
%LWFe: 0
%LVFe: 0

These are the true instrument transformer ratios. Normally they coincide with the Power Meter module's setup.

4. Configure your values as required.

For a detailed explanation of values and their calculations, see "Loss Compensation Input Parameters".

CONFIGURING LOSS COMPENSATION USING ION SETUP

1. Log on to ION Setup and connect to the appropriate meter.

2. Double-click the Setup Assistant and navigate to the Revenue > Transformer Loss screen.

3. Click the Method Selection tab to select how Transformer Loss information is entered.

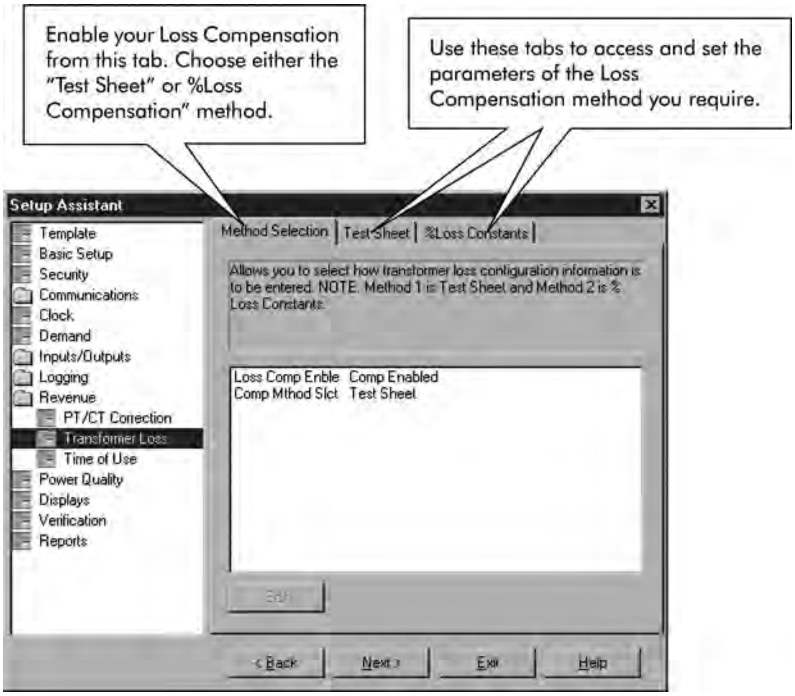
4. Click either the %Loss Constant or the Test Sheet tabs (depending on your selected calculation method) and configure the value settings.

SINGLE-PHASE TESTING IN ION SETUP

You can also test Transformer Line Loss with a single-phase source. To test with single-phase in ION Setup:

1. Log on to ION Setup and connect to the appropriate meter.

2. Double-click the Setup Assistant and select the Verification screen.


Enable your Loss Compensation from this tab. Choose either the "Test Sheet" or %Loss Compensation" method.

Use these tabs to access and set the parameters of the Loss Compensation method you require.

Setup Assistant

Allows you to select how transformer loss configuration information is to be entered. NOTE. Method 1 is Test Sheet and Method 2 is % Loss Constants.

Loss Comp Enble Comp Enabled
Comp Mthod Slct Test Sheet

3. Select Test Mode and click Display.

A window appears informing you the meter is now in test mode.

4. Select Volts, Amps and Power.

5. Click Loss Mode and select Single Phase.

6. In the Setup Assistant screen, navigate to Revenue > Transformer Loss and set your loss parameters.

LOSS COMPENSATION INPUT PARAMETERS

Depending on the method chosen for Transformer Loss Compensation, the meter requires specific data parameters to be programmed into the meter. The data for each method is listed below. All parameters can be programmed into the meter using ION software.

The following is a detailed description of the input parameters required by both methods.

INPUT PARAMETERS FOR METHOD 1: "TEST SHEET"

Line losses and transformer losses are calculated separately and applied to the measured power, energy and demand quantities based on the location of the meter with regards to the power transformer, supply-side line and load-side line.

All parameters required for this method can be obtained from the transformer and line manufacturer.

The same unit of length (meter or foot) must be used for all parameters.

Line loss calculation parameters:

$$\text{Power Transformer Ratio} = \left(\frac{\text{Voltage on supply side}}{\text{Voltage on load side}}\right)$$

The value of Power Transformer Ratio will be less than 1 for generation applications. If there is no power transformer used, set this value to 1.

For the line on the supply side (SY) of the transformer:

$$\text{Resistance/Unit length} \left(\frac{r}{l}_{sy}\right) \text{ in } [\Omega/m] \text{ or } [\Omega/ft]$$

$$\text{Reactance/Unit length} \left(\frac{x}{l}_{sy}\right) \text{ in } [\Omega/m] \text{ or } [\Omega/ft]$$

$$\text{Line length}_{sy} \text{ in } [m] \text{ or } [ft]$$

For the line on the load side (LD) of the transformer:

$$\text{Resistance/Unit length} \left(\frac{r}{l}_{ld}\right) \text{ in } [\Omega/m] \text{ or } [\Omega/ft]$$

$$\text{Reactance/Unit length} \left(\frac{x}{l}_{ld}\right) \text{ in } [\Omega/m] \text{ or } [\Omega/ft]$$

$$\text{Line length}_{ld} \text{ in } [m] \text{ or } [ft]$$

ION meters then calculate the line losses as:

$$LLW[W] = I^2_{avg} \times \frac{r}{l} \times \text{Line Length} \times 3 \qquad (13a)$$

$$LLV[VAR] = I^2_{avg} \times \frac{x}{l} \times \text{Line Length} \times 3 \qquad (13b)$$

These calculations are performed separately for the supply side part of the line and the load side part.

TRANSFORMER LOSS CALCULATION PARAMETERS:

When this method is selected, then the following power transformer and line data is programmed into the meter:

- Rated power transformer voltage (VLL on metered-side of Power Transformer)
- Rated power transformer kVA
- Power transformer ratio (Voltage on Supply Side/Voltage on Load Side)
- No-load iron test loss watts
- Full-load copper test loss watts
- Percent exciting current
- Percent impedance
- Line length of load-side and supply-side line
- Resistance and reactance per unit length for both lines
- Instrument transformer ratios (VTR, CTR)
- Information about the location of the meter with regards to the power transformer, supply-side line and load-side line

The iron and copper losses are then calculated using equations 7 to 12, based on the measured load current and voltage.

LINE LOSS AND TRANSFORMER LOSS COMPENSATION

Once the losses are calculated, you can add or subtract losses from the measured active and reactive power values in real-time.

Metering Location Parameters:

- MP Definition 1

This parameter indicates if the power monitor (metering point) is installed on the supply side of the transformer or the load side.

- MP Definition 2

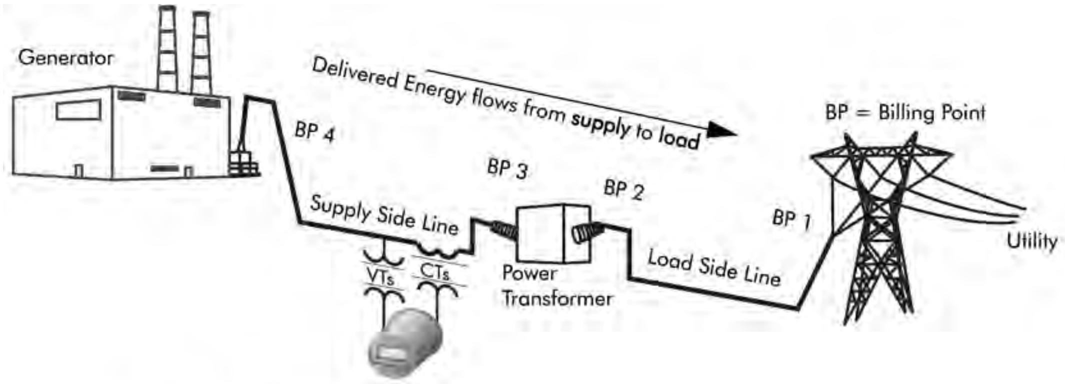
This parameter indicates if the power monitor (metering point) is installed on the transformer end of the line or on the far end.

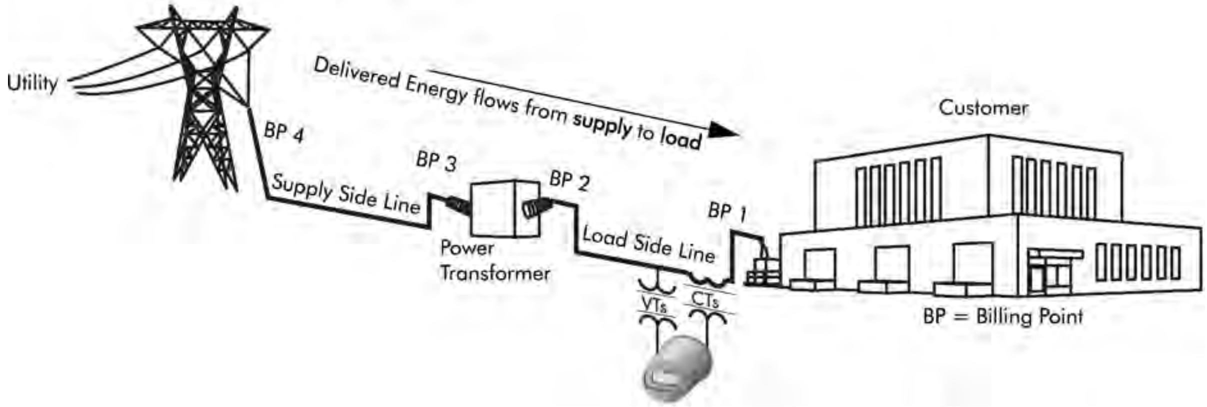
USE CASES: METERING POINT & BILLING POINT LOCATIONS

The following diagram outlines the possible locations of the billing points (BP) and metering points.

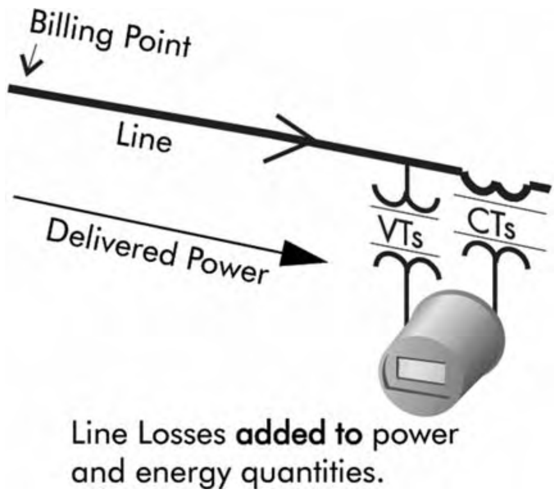
Some scenarios involve energy delivered from generator to the Utility, and others from the Utility to the customer.

The following examples show how the location of the power monitor and the billing point affect the calculation of compensated power values.



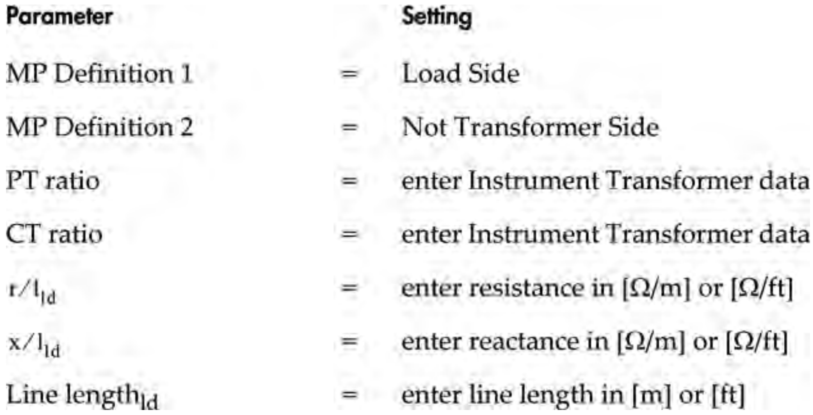


LINE LOSS ONLY



Adding Line Losses:

Line losses are added to the delivered power and energy quantities. Set the loss calculation parameters in the meter as follows:

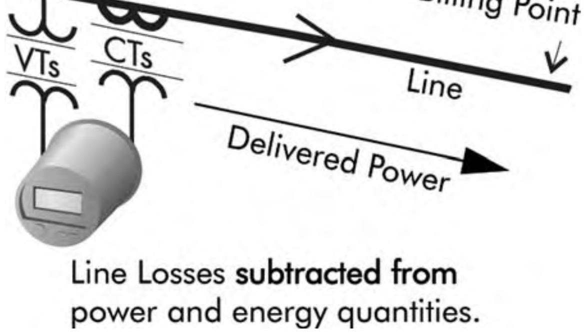


Parameter		Setting
MP Definition 1	=	Load Side
MP Definition 2	=	Not Transformer Side
PT ratio	=	enter Instrument Transformer data
CT ratio	=	enter Instrument Transformer data
r/l_{ld}	=	enter resistance in [Ω/m] or [Ω/ft]
x/l_{ld}	=	enter reactance in [Ω/m] or [Ω/ft]
Line length$_{ld}$	=	enter line length in [m] or [ft]

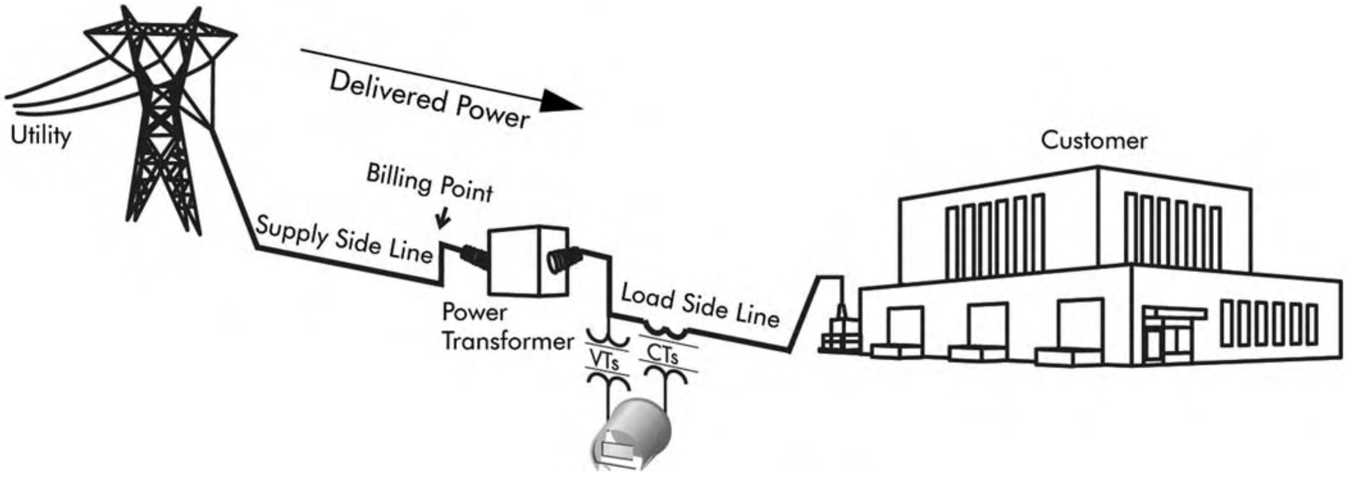
Leave all other parameters at their default settings.

Subtracting Line Losses:

Change MP Definition 2 to "Transformer Side" so that the line losses are subtracted from the power and energy quantities.



TRANSFORMER LOSS ONLY



Adding Transformer Losses:

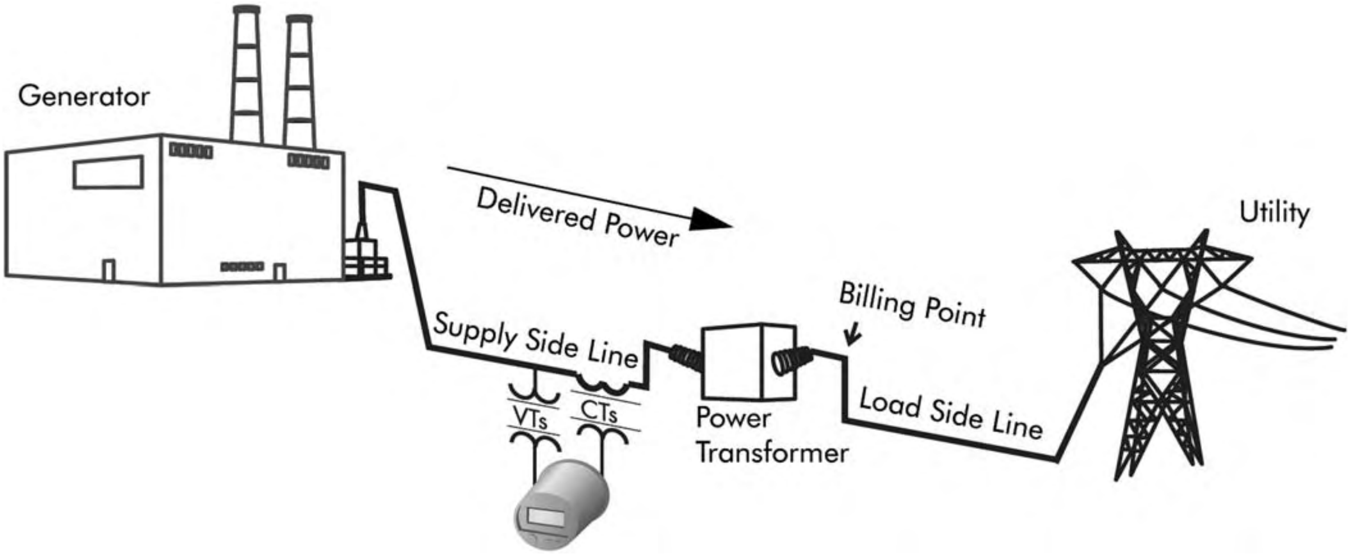
Transformer losses are added to power and energy quantities. The loss calculation parameters in the meter should be set as follows:

Parameter		**Setting**
MP Definition 1	=	Load Side
MP Definition 2	=	Transformer Side
PT ratio	=	enter Instrument Transformer data
CT ratio	=	enter Instrument Transformer data
Vll_{rated}	=	enter Transformer data
$LWFe_{test}$	=	enter Transformer data
$LWCu_{test}$	=	enter Transformer data
%Excitation	=	enter Transformer data
%Impedance	=	enter Transformer data

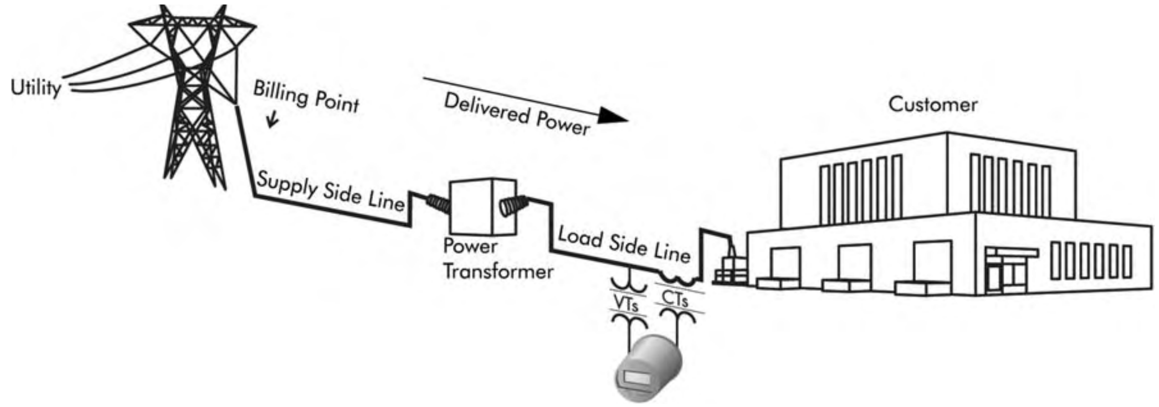
Leave all other parameters at their default settings.

Subtracting Transformer Losses:

Change MP Definition 1 to "Supply Side" so that transformer losses are subtracted from the power and energy quantities.



LINE LOSS AND TRANSFORMER LOSS



Adding Line & Transformer Losses:

The transformer and line losses are added to measured power and energy values. Set the meter's loss calculation parameters to:

Parameter		Setting
MP Definition 1	=	Load Side
MP Definition 2	=	Not Transformer Side
PT ratio	=	enter Instrument Transformer data
CT ratio	=	enter Instrument Transformer data
Power Transformer Ratio	=	(Voltage on Supply Side/Voltage on Load Side)
Vll_{rated}	=	enter Transformer data
$LWFe_{test}$	=	enter Transformer data
$LWCu_{test}$	=	enter Transformer data
%Excitation	=	enter Transformer data
%Impedance	=	enter Transformer data
r/l_{sy}	=	enter resistance in [Ω/m] or [Ω/ft]
x/l_{sy}	=	enter reactance in [Ω/m] or [Ω/ft]
Line $length_{sy}$	=	enter line length in [m] or [ft]
r/l_{LD}	=	enter resistance in [Ω/m] or [Ω/ft]
x/l_{LD}	=	enter reactance in [Ω/m] or [Ω/ft]
Line $length_{ld}$	=	enter line length in [m] or [ft]

Leave all other parameters at their default settings. To ignore load-side or supply-side line losses, set the corresponding length to zero.

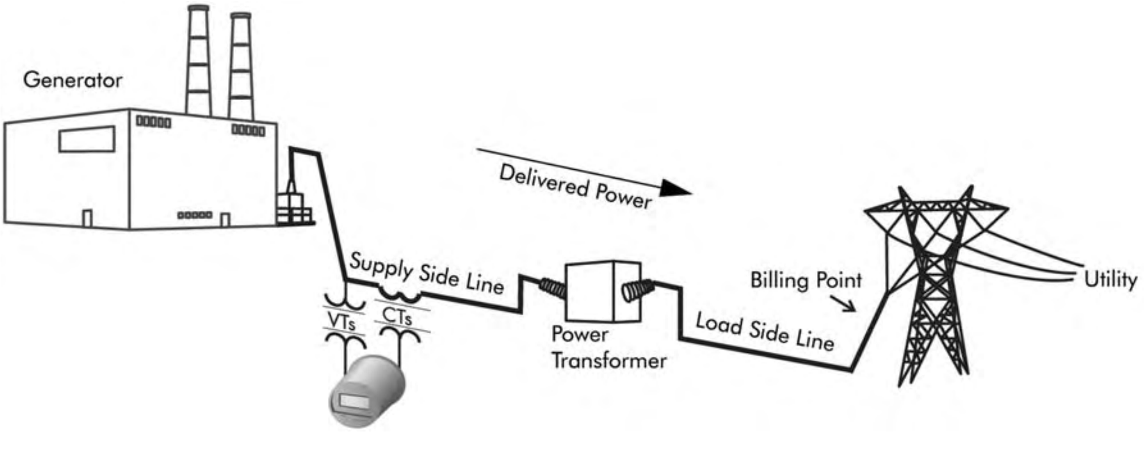
Subtracting Line & Transformer Losses:

Change the MP Definition 1 to "Supply Side" (see list of Parameters and Settings) so that losses are subtracted from power and energy quantities.

INPUT PARAMETERS FOR METHOD 2: "% LOSS CONSTANTS"

When using this method in ION meters with a delta connection, compute the %Loss values with respect to the single-phase system kVA. To confirm TLC operation, verify that the amount of compensated watts matches the expected.

In this method, line loss and transformer loss calculation parameters are computed manually or through a third party program into four (4) loss constants. These values are then programmed into the meter. The meter uses these constants to calculate the losses and perform the compensation.



This method allows you to enable or disable iron and copper loss calculations separately. When this method is selected, the following data must be programmed into the meter:

- Percent iron Watt loss constant (%LWFe)*
- Percent copper Watt loss constant (%LWCu)*
- Percent iron VAR loss constant (%LVFe)*
- Percent copper VAR loss constant (%LVCu)*
- Instrument transformer ratios (VTR, CTR)
- Rated meter voltage (VMrated)
- 1/2 Class meter current (1/2IMrated)
- Number of stator elements (2 for Delta connections, 3 for WYE)

* If you want the losses to be subtracted from Delivered Energy, enter negative values for the percent loss constants.

The field "# stator elements" indicate the number of metering elements to configure for transformer loss compensation:

ION8300/ ION8400/ ION8500 Volts Mode	ION7550, ION7650 Meters Volts Mode	Number of stator elements
35S	Delta	2
9S, 36S	4-Wire WYE 3-Wire WYE	3

These are the values you program into the ION meter. To properly implement Transformer Loss Calculations using Method 2, you must calculate constants using the following relationships. See "Appendix A: Glossary" and ensure you fully understand the terms used below. Failure to calculate exactly as outlined below will result in incorrect readings.

PERCENT-LOSS CONSTANT CALCULATIONS

Both L-L, or both L-N

$$\%LWFe = \frac{LWFe_{TXtest} \times \left[\frac{V_{Mrated} \times VTR}{V_{TXtest}}\right]^2}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

Both L-L, or both L-N

$$\%LVFe = \frac{LVFe_{TXtest} \times \left[\frac{V_{Mrated} \times VTR}{V_{TXtest}}\right]^4}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

$$\%LWCu = \frac{LWCu_{TXtest} \times \left[\frac{\frac{1}{2}I_{Mclass} \times CTR}{I_{TXtest}}\right]^2 + LLW_{Mclass}}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

$$= \frac{(\frac{1}{2}I_{Mclass} \times CTR)^2 \times \text{Total System Resistance}}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

System Resistance and System Reactance include both transformer and line impedance.

$$\%LVCu = \frac{LVCu_{TXtest} \times \left[\frac{\frac{1}{2}I_{Mclass} \times CTR}{I_{TXtest}}\right]^2 + LLW_{Mclass}}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

$$= \frac{(\frac{1}{2}I_{Mclass} \times CTR)^2 \times \text{Total System Reactance}}{\frac{1}{2}\text{ Class System VA}} \times 100\%$$

LOSS CALCULATIONS IN ION METERS

ION meters use these constants to calculate the losses as follows:

$$LWFe = \frac{\%LWFe}{100} \times \frac{1}{2}\text{ Class System VA} \times \left[\frac{V_{actual}}{V_{Mrated}}\right]^2 \qquad (19)$$

$$LVFe = \frac{\%LVFe}{100} \times \frac{1}{2}\text{ Class System VA} \times \left[\frac{V_{actual}}{V_{Mrated}}\right]^4 \qquad (20)$$

$$LWCu = \frac{\%LWCu}{100} \times \frac{1}{2}\text{ Class System VA} \times \left[\frac{I_{actual}}{\frac{1}{2}I_{Mclass}}\right]^2 \qquad (21)$$

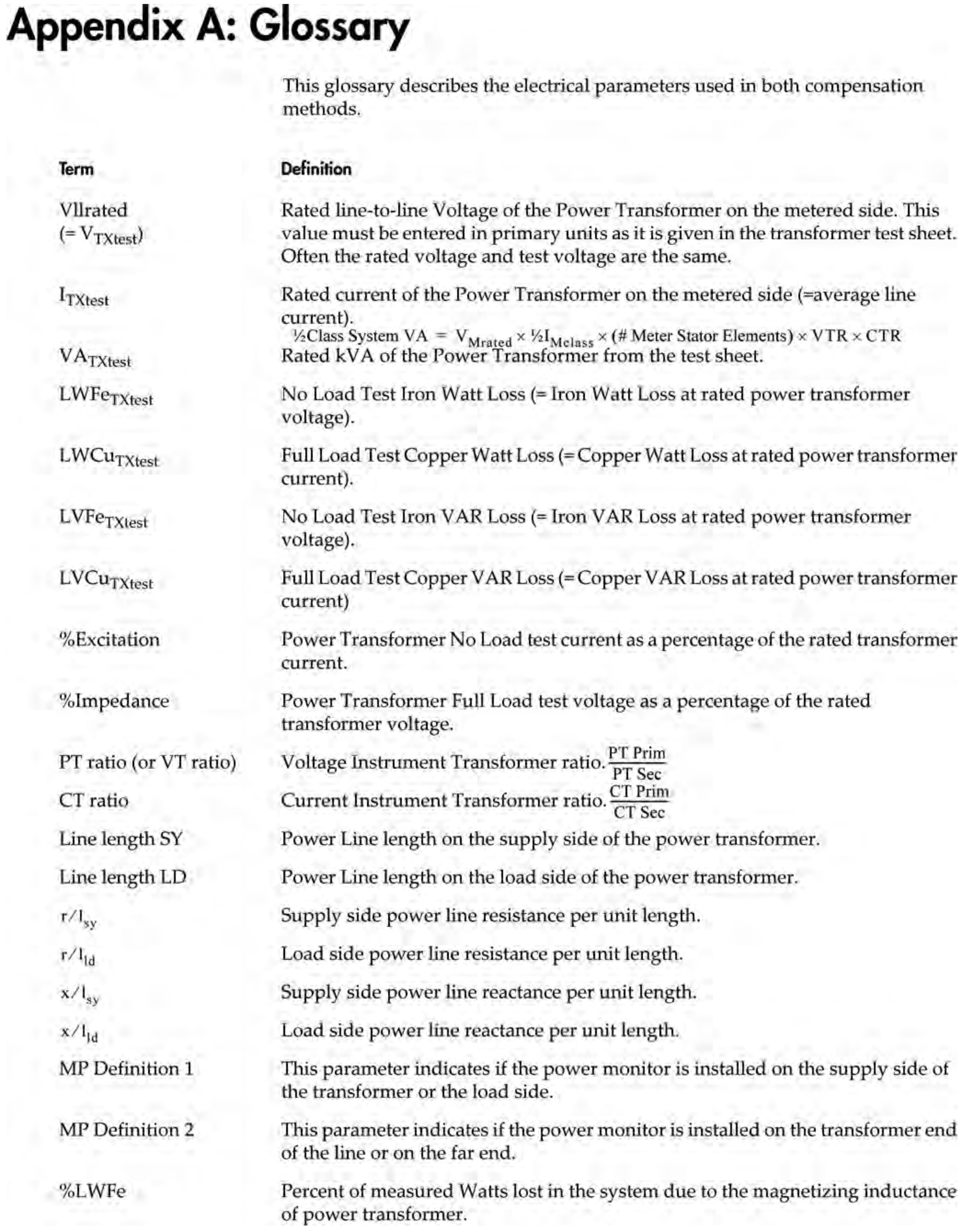
$$LVCu = \frac{\%LVCu}{100} \times \frac{1}{2}\text{ Class System VA} \times \left[\frac{I_{actual}}{\frac{1}{2}I_{Mclass}}\right]^2 \qquad (22)$$

Important Note for Percent-Loss Loss Equations (14-17) and Power Loss Equations (19 - 22)

Because the meter's first step in its "Loss Calculations" computation is to cancel out the "1/2 Class System VA" value, the "1/2 Class System VA" value that is used in the "Percent-Loss Constant Calculations" on page 16 must be calculated exactly as outlined in equation 18 (above). If the "1/2 Class System VA" value is not what the meter expects, the two terms will not fully cancel out. This will result in incorrect loss calculations.

APPENDIX A: GLOSSARY

This glossary describes the electrical parameters used in both compensation methods.



Appendix A: Glossary

This glossary describes the electrical parameters used in both compensation methods.

Term	Definition
Vllrated (= V_{TXtest})	Rated line-to-line Voltage of the Power Transformer on the metered side. This value must be entered in primary units as it is given in the transformer test sheet. Often the rated voltage and test voltage are the same.
I_{TXtest}	Rated current of the Power Transformer on the metered side (=average line current). ½Class System VA = V_{Mrated} × ½I_{Mclass} × (# Meter Stator Elements) × VTR × CTR
VA_{TXtest}	Rated kVA of the Power Transformer from the test sheet.
$LWFe_{TXtest}$	No Load Test Iron Watt Loss (= Iron Watt Loss at rated power transformer voltage).
$LWCu_{TXtest}$	Full Load Test Copper Watt Loss (= Copper Watt Loss at rated power transformer current).
$LVFe_{TXtest}$	No Load Test Iron VAR Loss (= Iron VAR Loss at rated power transformer voltage).
$LVCu_{TXtest}$	Full Load Test Copper VAR Loss (= Copper VAR Loss at rated power transformer current)
%Excitation	Power Transformer No Load test current as a percentage of the rated transformer current.
%Impedance	Power Transformer Full Load test voltage as a percentage of the rated transformer voltage.
PT ratio (or VT ratio)	Voltage Instrument Transformer ratio. $\frac{\text{PT Prim}}{\text{PT Sec}}$
CT ratio	Current Instrument Transformer ratio. $\frac{\text{CT Prim}}{\text{CT Sec}}$
Line length SY	Power Line length on the supply side of the power transformer.
Line length LD	Power Line length on the load side of the power transformer.
r/l_{sy}	Supply side power line resistance per unit length.
r/l_{ld}	Load side power line resistance per unit length.
x/l_{sy}	Supply side power line reactance per unit length.
x/l_{ld}	Load side power line reactance per unit length.
MP Definition 1	This parameter indicates if the power monitor is installed on the supply side of the transformer or the load side.
MP Definition 2	This parameter indicates if the power monitor is installed on the transformer end of the line or on the far end.
%LWFe	Percent of measured Watts lost in the system due to the magnetizing inductance of power transformer.

%LWCu	Percent of measured Watts lost in the system due to impedance in lines and windings.
%LVFe	Percent of measured VARs lost in the system due to the magnetizing inductance of power transformer.
%LVCu	Percent of measured VARs lost in the system due to impedance in lines and windings.
System Resistance	Sum of power transformer and line resistance on all phases.
System Reactance	Sum of power transformer and line reactance on all phases.
V_{Mrated} (Rated Meter Voltage)	Nominal meter input voltage. This is the value used in the calculation of the Percent Iron Loss constants. The rated meter voltage will be a line-to-neutral voltage for 3 element metering and a line-to-line voltage for 2 element metering. The Rated Meter Voltage must be entered in meter units (= unscaled).
½I_{Mrated} (½ Class Meter Current)	Half the value of the certified meter class current. This value has to match the value used in the calculation of the Percent Loss Constants.
# of Stator Elements	Number of measuring elements used in the meter. This number is determined by the form factor of the power monitor. 9S meters for example in a 4 wire application use 3 elements. 35S meters used for 3 wire applications use 2 elements.
LLV_{Mclass}	Line loss VARs at the meter's ½ class current.
LLW_{Mclass}	Line Loss Watts at the meter's ½ class current.

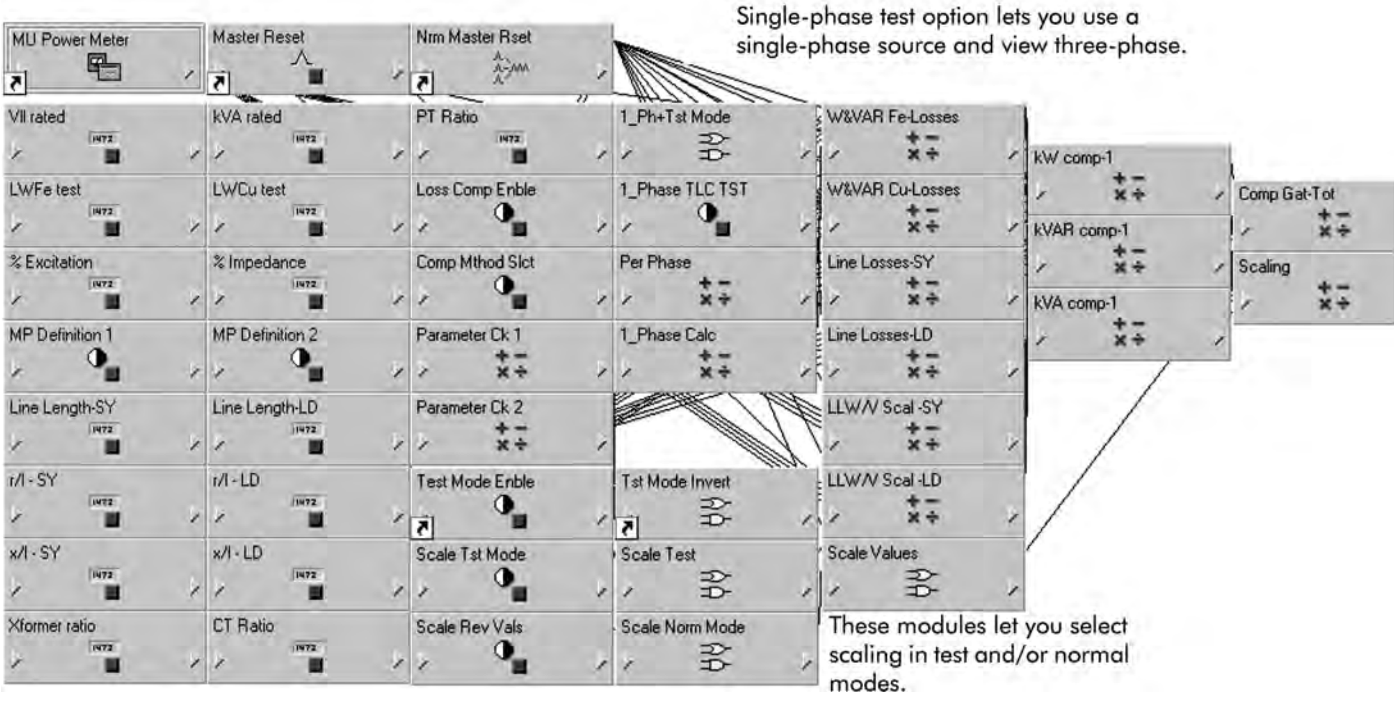
APPENDIX B: LOSS COMPENSATION FRAMEWORKS

METHOD 1: "TEST SHEET"

The following screen capture shows the view of this framework in Designer:

On the left side are the External Numeric and External Boolean modules that are used to enter transformer and line data for the loss calculations. The Arithmetic modules perform the actual calculations.

Before the transformer and line data is passed into the Arithmetic modules that perform the loss calculations, the data is checked for invalid entries such as negative numbers to ensure that the outputs of the Arithmetic loss modules will always be available.



Single-phase test option lets you use a single-phase source and view three-phase.

These modules let you select scaling in test and/or normal modes.

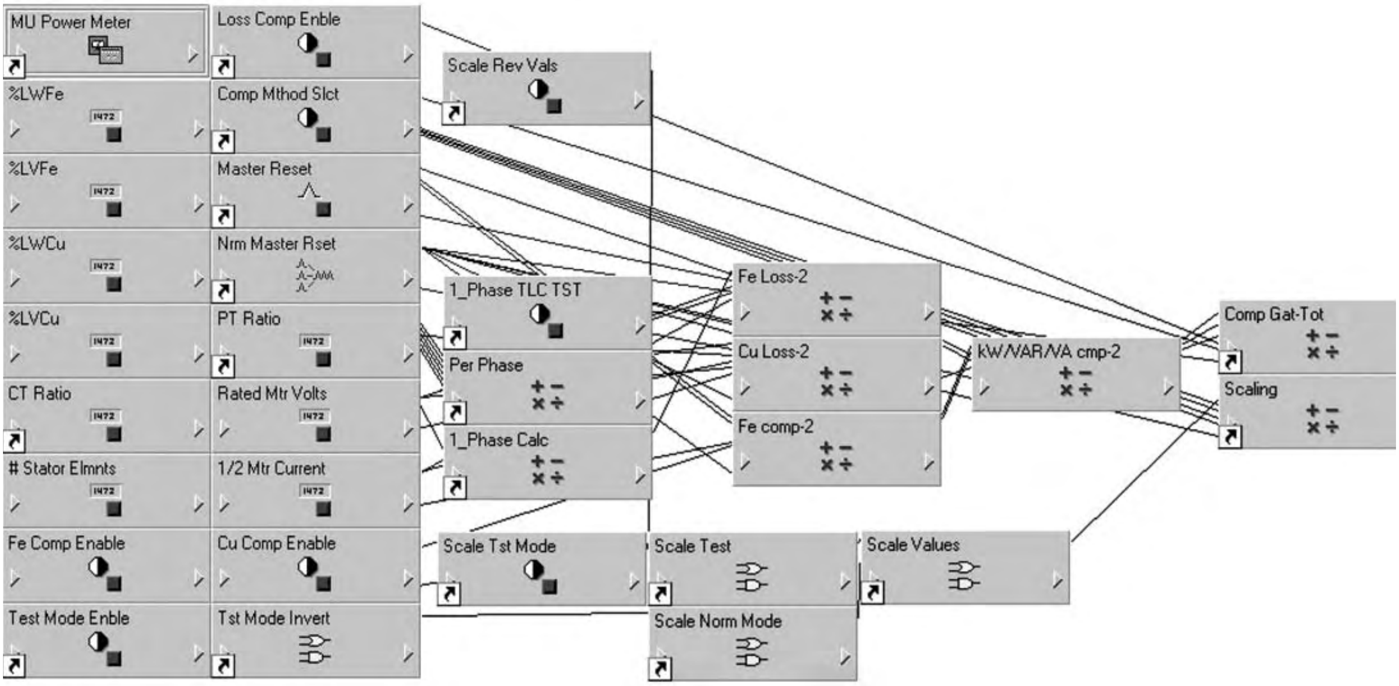
A division by "0" or a negative number in a square root would cause a "Not available" output on the Arithmetic modules.

Line loss totals must be scaled prior to final energy scaling since the line losses are I2R (measured in Watts). Note that there is no voltage component in this Watts measurement. Scaling line loss prior to final power scaling provides CT2 as a multiplier for line losses:

$$\begin{aligned}\text{Line Loss} &= [\text{Losses in MU}] \times [\text{PTR} \times \text{CTR}] \\ &= \left[\frac{(I_{sec} \times \text{CTR})^2 \times R}{\text{PTR} \times \text{CTR}}\right] \times (\text{PTR} \times \text{CTR}) \\ &= \left[(I_{sec})^2 \times R \times \frac{\text{CTR}}{\text{PTR}}\right] \times (\text{PTR} \times \text{CTR})\end{aligned}$$

METHOD 2: "%LOSS CONSTANTS"

The following screen capture shows the view of the framework in Designer:



On the left side are the External Numeric and External Boolean modules that are used to enter transformer and line data for the loss calculations. The Arithmetic modules perform the actual calculations.

SINGLE-PHASE TESTING

You can connect a single-phase source voltage in parallel and the current in series to simulate a three-phase source. Some ION meters automatically adjust the voltage in this test situation when the meter is in Test Mode and the single-phase option is selected.

THE ART & SCIENCE OF PRODUCTIVE RELAYING - VOLTAGE TRANSFORMERS

C. Russell Mason, General Electric

Two types of voltage transformer are used for protective-relaying purposes, as follows: (1) the "instrument potential transformer," hereafter to be called simply "potential transformer," and (2) the "capacitance potential device". A potential transformer is a conventional transformer having primary and secondary windings. The primary winding is connected directly to the power circuit either between two phases or between one phase and ground, depending on the rating of the transformer and on the requirements of the application. A capacitance potential device is a voltage-transforming equipment using a capacitance voltage divider connected between phase and ground of a power circuit.

ACCURACY OF POTENTIAL TRANSFORMERS

The ratio and phase-angle inaccuracies of any standard ASA accuracy class1 of potential transformers are so small that they may be neglected for protective-relaying purposes if the burden is within the "thermal" volt-ampere rating of the transformer. This thermal volt-ampere rating corresponds to the full-load rating of a power transformer. It is higher than the volt-ampere rating used to classify potential transformers as to accuracy for metering purposes. Based on the thermal volt-ampere rating, the equivalent-circuit impedances of potential transformers are comparable to those of distribution transformers.

The "burden" is the total external volt-ampere load on the secondary at rated secondary voltage. Where several loads are connected in parallel, it is usually sufficiently accurate to add their individual volt-amperes arithmetically to determine the total volt-ampere burden.

If a potential transformer has acceptable accuracy at its rated voltage, it is suitable over the range from zero to 110% of rated less voltage. Operation in excess of 10% overvoltage may cause increased errors and excessive heating.

Where precise accuracy data are required, they can be obtained from ratio-correction factor curves and phase-angle-correction curves supplied by the manufacturer.

CAPACITANCE POTENTIAL DEVICES

Two types of capacitance potential device are used for protective relaying: (1) the "coupling-capacitor potential device," and (2) the "bushing potential device". The two devices are basically alike, the principal difference being in the type of capacitance voltage divider used, which in turn affects their rated burden. The coupling-capacitor device uses as a voltage divider a "coupling capacitor" consisting of a stack of series-connected capacitor units, and an "auxiliary capacitor", as shown schematically in Fig. 1. The bushing device uses the capacitance coupling of a specially constructed bushing of a circuit breaker or power transformer, as shown schematically in Fig. 2.

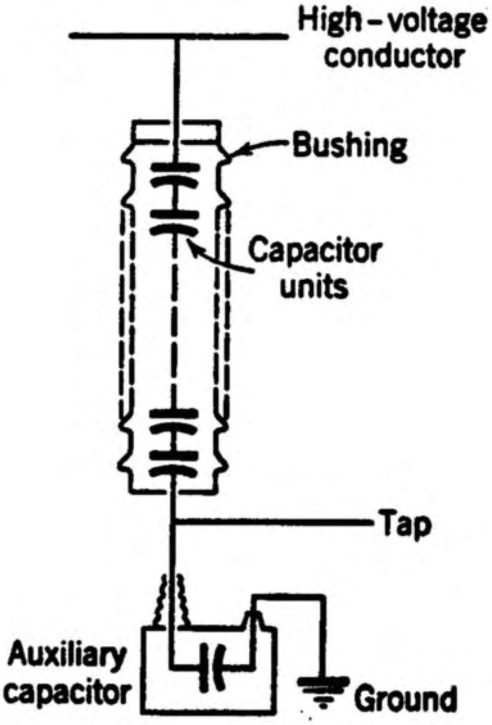


Fig. 1 Coupling-capacitor voltage divider.

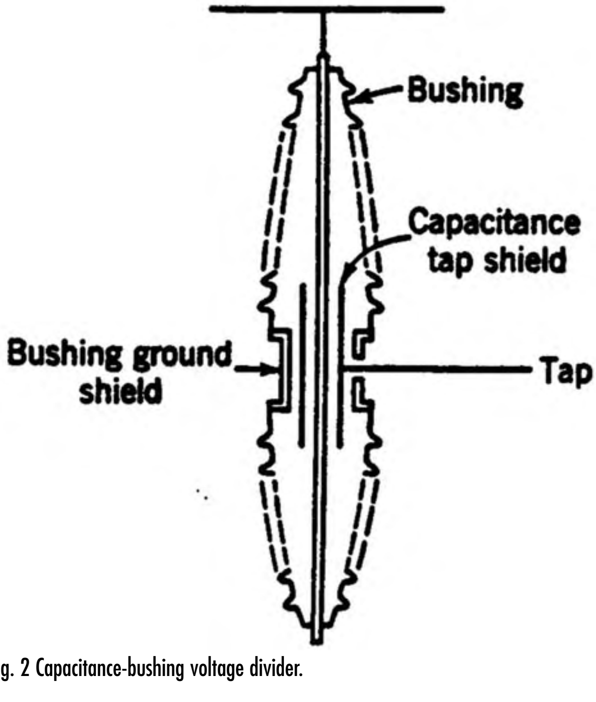


Fig. 2 Capacitance-bushing voltage divider.

Both of these relaying potential devices are called "Class A" devices. They are also sometimes called "In-phase" or "Resonant" devices for reasons that will be evident later.

Other types of potential devices, called "Class C" or "Out-of-phase" or "Non-resonant", are also described in References 2 and 3, but they are not generally suitable for protective relaying, and therefore they will not be considered further here.

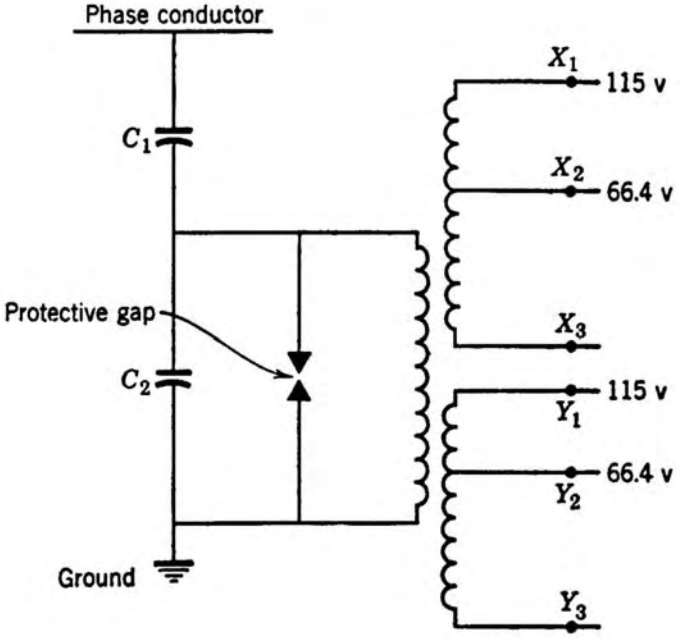


Fig. 3. Schematic diagram of a Class A potential device.

A schematic diagram of a Class A potential device including the capacitance voltage divider is shown in Fig. 3. Not shown are the means for adjusting the magnitude and phase angle of the secondary voltage; the means for making these adjustments vary with different manufacturers, and a knowledge of them is not essential to our present purposes.

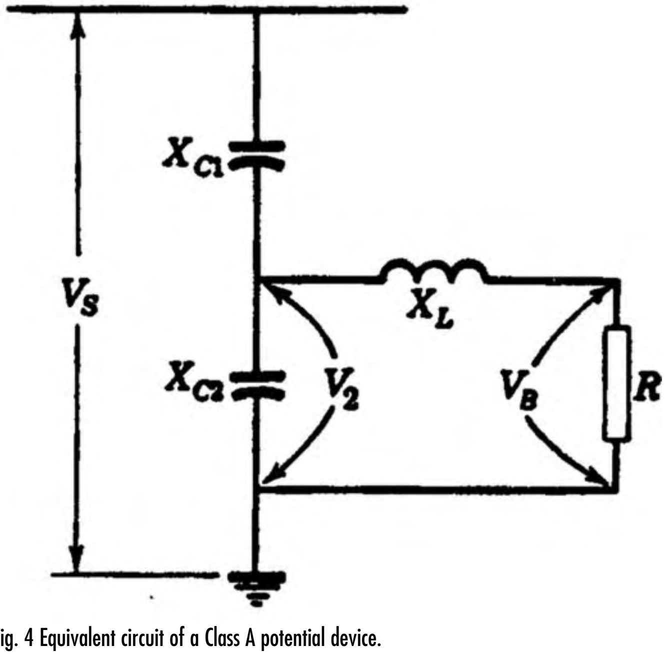


Fig. 4 Equivalent circuit of a Class A potential device.

The Class A device has two secondary windings as shown. Both windings are rated 115 volts, and one must have a 66.4-volt tap. These windings are connected in combination with the windings of the devices of the other two phases of a three-phase power circuit. The connection is "wye" for phase relays and "broken delta" for ground relays. These connections will be illustrated later. The equivalent circuit of a Class A device is shown in Fig. 4. The equivalent reactance XL, is adjustable to make the burden voltage VB be in phase with the phase-to-ground voltage of the system VS. The burden is shown as a resistor because, so far as it is possible, it is the practice to correct the power factor of the burden approximately to unity by the use of auxiliary capacitance burden. When the device is properly adjusted,

$$X_L = \frac{X_{C1}X_{C2}}{X_{C1}+X_{C2}} \quad (1)$$

which explains why the term "Resonant" is applied to this device. Actually, XC2 is so small compared with XC1 that XL is practically equal to XC2. Therefore, XL and XC2 would be practically in parallel resonance were it not for the presence of the burden impedance.

The gross input in watts from a power circuit to a capacitance potential-device network is:

$$W = 2\pi f C_1 V_S V_2 \sin\alpha \quad \text{watts} \quad (2)$$

where f = power-system frequency.
a = phase angle between VS and V2
C1 = capacitance of main capacitor (see Fig. 3) in farads.

VS and V2 are volts defined as in Fig. 4. If the losses in the network are neglected, equation 2 will give the output of the device. For special applications, this relation is useful for estimating the rated burden from the known rated burden under standard conditions; it is only necessary to compare the proportions in the two cases, remembering that, for a given rating of equipment, the tap voltage V2 varies directly as the applied voltage VS.

For a given group of coupling-capacitor potential devices, the product of the capacitance of the main capacitor C1 and the rated circuit-voltage value of VS is practically constant; in other words, the number of series capacitor units that comprise C1 is approximately directly proportional to the rated circuit voltage. The capacitance of the auxiliary capacitor C2 is the same for all rated circuit voltages, so as to maintain an approximately constant value of the tap voltage V2 for all values of rated circuit voltage.

For bushing potential devices, the value of C1 is approximately constant over a range of rated voltages, and the value of C2 is varied by the use of auxiliary capacitance to maintain an approximately constant value of the tap voltage V2 for all values of rated circuit voltage.

STANDARD RATED BURDENS OF CLASS A POTENTIAL DEVICES

The rated burden of a secondary winding of a capacitance potential device is specified in watts at rated secondary voltage when rated phase-to-ground voltage is impressed across the capacitance voltage divider. The rated burden of the device is the sum of the watt burdens that may be impressed on both secondary windings simultaneously.

Adjustment capacitors are provided in the device for connecting in parallel with the burden on one secondary winding to correct the total-burden power factor to unity or slightly leading.

The standard rated burdens of bushing potential devices are given in Table 1.

Rated Circuit Voltage, kv		Rated Burden, watts
Phase-to-Phase	Phase-to-Ground	
115	66.4	25
138	79.7	35
161	93.0	45
230	133.0	80
287	166.0	100

Table 1. Rated Burdens of Bushing Potential Devices

The rated burden of coupling-capacitor potential devices is 150 watts for any of the rated circuit voltages, including those of Table 1.

STANDARD ACCURACY OF CLASS A POTENTIAL DEVICES

Table 2 gives the standard maximum deviation in voltage ratio and phase angle for rated burden and for various values of primary voltage, with the device adjusted for the specified accuracy at rated primary voltage.

Primary Voltage, percent of rated	Maximum Deviation	
	Ratio, percent	Phase Angle, degrees
100	± 1.0	± 1.0
25	± 3.0	± 3.0
5	± 5.0	± 5.0

Table 2. Ratio and Phase-Angle Error versus Voltage

Table 3 gives the standard maximum deviation in voltage ratio and phase angle for rated voltage and for various values of burden with the device adjusted for the specified accuracy at rated burden.

Burden, percent of rated	Maximum Deviation	
	Ratio, percent	Phase Angle, degrees
100	± 1.0	± 1
50	± 6.0	± 4
0	± 12.0	± 8

Table 3. Ratio and Phase-Angle Error versus Burden

Table 3 shows that for greatest accuracy, the burden should not be changed without readjusting the device.

EFFECT OF OVERLOADING

As the burden is increased beyond the rated value, the errors will increase at about the rate shown by extrapolating the data of Table 3, which is not very serious for protective relaying. Apart from the possibility of overheating, the serious effect is the accompanying increase of the tap voltage (V2 of Fig. 4). An examination of the equivalent circuit, Fig. 4, will show why the tap voltage increases with increasing burden. It has been said that XL is nearly equal to XC2, and therefore these two branches of the circuit will approach parallel resonance as R is decreased (or, in other words, as the burden is increased). Hence, the tap voltage will tend to approach VS. As the burden is increased above the rated value, the tap voltage will increase approximately proportionally.

The objection to increasing the tap voltage is that the protective gap must then be adjusted for higher-than-normal arc-over voltage. This lessens the protection afforded the equipment. The circuit elements protected by the gap are specified to withstand 4 times the normal tap voltage for 1 minute. Ordinarily, the gap is adjusted to arc over at about twice normal voltage. This is about as low an arc-over as the gap may be adjusted to have in view of the fact that for some ground faults the applied voltage (and hence the tap voltage) may rise to √3 times normal. Obviously, the gap must not be permitted to arc over for any voltage for which the protective-relaying equipment must function. Since the ground-relay burden loads the devices only when a ground fault occurs, gap flashover may be a problem when thermal overloading is not a problem. Before purposely overloading a capacitance potential device, one should consult the manufacturer.

As might be suspected, short-circuiting the secondary terminals of the device (which is extreme overloading) will arc over the gap continuously while the short circuit exists. This may not cause any damage to the device, and hence it may not call for fusing, but the gap will eventually be damaged to such an extent that it may no longer protect the equipment.

Even when properly adjusted, the protective gap might arc over during transient overvoltages caused by switching or by lightning. The duration of such arc-over is so short that it will not interfere with the proper operation of protective relays. The moment the overvoltage ceases, the gap will stop arcing over because the impedance of the main capacitor C1 is so high that normal system voltage cannot maintain the arc.

It is emphasized that the standard rated burdens are specified as though a device were connected and loaded as a single-phase device. In practice, however, the secondary windings of three devices are interconnected and loaded jointly. Therefore, to determine the actual loading on a particular device under unbalanced voltage conditions, as when short circuits occur, certain conversions must be made. This is described later in more detail for the broken-delta burden. Also, the effective burden on each device resulting from the phase-to-phase and phase-to-neutral burdens should be determined if the loading is critical; this is merely a circuit problem that is applicable to any kind of voltage transformer.

NON-LINEAR BURDENS

A “non-linear” burden is a burden whose impedance decreases because of magnetic saturation when the impressed voltage is increased. Too much non-linearity in its burden will let a capacitance potential device get into a state of ferroresonance, during which steady overvoltages of highly distorted waveform will exist across the burden. Since these voltages bear no resemblance to the primary voltages, such a condition must be avoided.

If one must know the maximum tolerable degree of non-linearity, he should consult the manufacturer. Otherwise, the ferroresonance condition can be avoided if all magnetic circuits constituting the burden operate at rated voltage at such low flux density that any possible momentary overvoltage will not cause the flux density of any magnetic circuit to go beyond the knee of its magnetization curve (or, in other words, will not cause the flux density to exceed about 100,000 lines per square inch). Since the potential-device secondary-winding voltage may rise to √3 times rated, and the broken-delta voltage may rise to √3 times rated, the corresponding phase-to-neutral and broken-delta burdens may be required to have no more than 1/√3 and 1/3, respectively, of the maximum allowable flux density at rated voltage.

If burdens with closed magnetic circuits, such as auxiliary potential transformers, are not used, there is no likelihood of ferroresonance. Class A potential devices are provided with two secondary-windings purposely to avoid the need of an auxiliary potential transformer.

The relays, meters, and instruments generally used have air gaps in their magnetic circuits, or operate at low enough flux density to make their burdens sufficiently linear.

THE BROKEN-DELTA BURDEN AND THE WINDING BURDEN

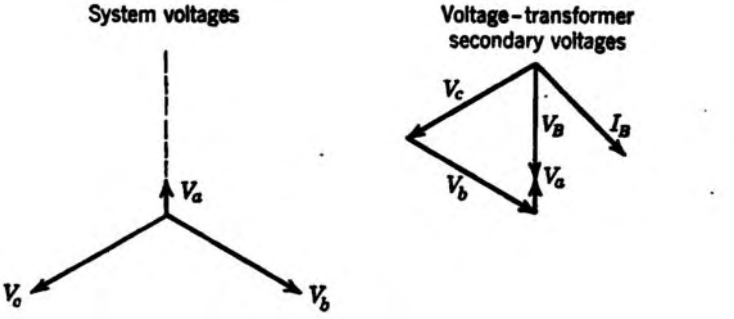
The broken-delta burden is usually composed of the voltage-polarizing coils of ground directional relays. Each relay’s voltage-coil circuit contains a series capacitor to make the relay have a lagging angle of maximum torque. Consequently, the voltage-coil circuit has a leading power factor. The volt-ampere burden of each relay is expressed by the manufacturer in terms of the rated voltage of the relay. The broken-delta burden must be expressed in terms of the rated voltage of the potential-device winding or the tapped portion of the winding — whichever is used for making up the broken-delta connection. If the relay- and winding-voltage ratings are the same, the broken-delta burden is the sum of the relay burdens. If the voltage ratings are different, we must re-express the relay burdens in terms of the voltage rating of the broken-delta winding before adding them, remembering that the volt-ampere burden will vary as the square of the voltage, assuming no saturation.

The actual volt-ampere burdens imposed on the individual windings comprising the broken-delta connection are highly variable and are only indirectly related to the broken-delta burden. Normally, the three winding voltages add vectorially to zero. Therefore, no current flows in the circuit, and the burden on any of the windings is zero. When ground faults occur, the voltage that appears across the broken-delta burden corresponds to 3 times the zero-phase-sequence component of any one of the three phase-to-ground voltages at the potential-device location. We shall call this voltage “3V0”. What the actual magnitude of this voltage is depends on how solidly the system neutrals are grounded, on the location of the fault with respect to the potential device in question, and on the configuration of the transmission circuits so far as it affects the magnitude of the zero-phase-sequence reactance. For faults at the potential-device location, for which the voltage is highest, 3V0 can vary approximately from 1 to 3 times the rated voltage of each of the broken-delta windings. (This voltage can go even higher in an ungrounded-neutral system should a state of ferroresonance exist, but this possibility is not considered here because it must not be permitted to exist.) If we assume no magnetic saturation in the burden, its maximum current magnitude will vary with the voltage over a 1 to 3 range.

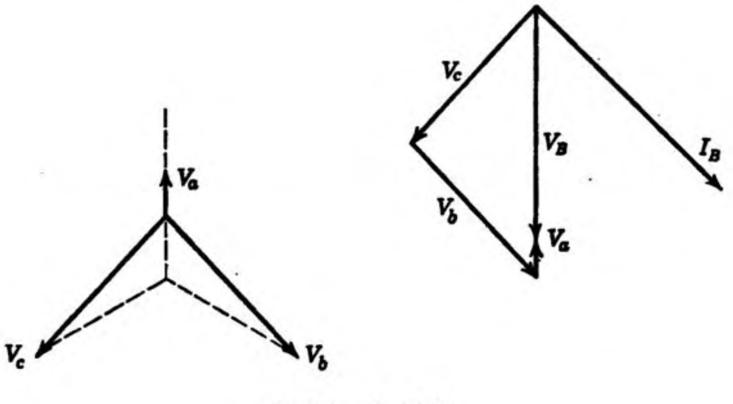
The burden current flows through the three broken-delta windings in series. As shown in Fig. 5, the current is at a different phase angle with respect to each of the winding voltages.

Since a ground fault can occur on any phase, the positions of any of the voltages of Fig. 5 relative to the burden current can be interchanged. Consequently, the burden on each winding may have a wide variety of characteristics under different circumstances.

Another peculiarity of the broken-delta burden is that the load is really carried by the windings of the unfaulted phases, and that the voltages of these windings do not vary in direct proportion to the voltage across the broken-delta burden. The voltages of the unfaulted-phase windings are not nearly as variable as the broken-delta-burden voltage.



No neutral shift



Partial neutral shift

Fig. 5. Broken-delta voltages and current for a single-phase-to-ground fault on phase a some distance from the voltage transformer.

The winding voltages of the unfaulted phases vary from approximately rated voltage to √3 times rated, while the broken-delta-burden voltage, and hence the current, is varying from less than rated to approximately 3 times rated.

As a consequence of the foregoing, on the basis of rated voltage, the burden on any winding can vary from less than the broken-delta burden to √3 times it. For estimating purposes, the √3 multiplier would be used, but, if the total burden appeared to be excessive, one would want to calculate the actual burden. To do this, the following steps are involved:

1. Calculate 3V0 for a single-phase-to-ground fault at the potential-device location, and express this in secondary-voltage terms, using as a potential-device ratio the ratio of normal phase-to-ground voltage to the rated voltage of the broken-delta windings.
2. Divide 3V0 by the impedance of the broken-delta burden to get the magnitude of current that will circulate in each of the broken-delta windings.
3. Calculate the phase-to-ground voltage (Vb1 + Vb2 + Vb0 etc.) of each of the two unfaulted phases at the voltage-transformer location, and express it in secondary-voltage terms as for 3V0.
4. Multiply the current of (2) by each voltage of (3).
5. Express the volt-amperes of (4) in terms of the rated voltage of the broken-delta windings by multiplying the volt-amperes of (4) by the ratio:

$$\left[\frac{V_{\text{rated}}}{\text{Voltage of 3}}\right]^2$$

It is the practice to treat the volt-ampere burden as though it were a watt burden on each of the three windings. It will be evident from Fig. 5 that, depending on which phase is grounded, the volt-ampere burden on any winding could be practically all watts.

It is not the usual practice to correct the power factor of the broken-delta burden to unity as is done for the phase burden. Because this burden usually has a leading power factor, to correct the power factor to unity would require an adjustable auxiliary burden that had inductive reactance. Such a burden would have to have very low resistance and yet it would have to be linear. In the face of these severe requirements, and in view of the fact that the broken-delta burden is usually a small part of the total potential-device burden, such corrective burden is not provided in standard potential devices.

COUPLING-CAPACITOR INSULATION COORDINATION AND ITS EFFECT ON THE RATED BURDEN

The voltage rating of a coupling capacitor that is used with protective relaying should be such that its insulation will withstand the flashover voltage of the circuit at the point where the capacitor is connected. Table 4 lists the standard capacitor withstand test voltages for some circuit-voltage ratings for altitudes below 3300 feet. The flashover voltage of the circuit at the capacitor location will depend not only on the line insulation but also on the insulation of other terminal equipment such as circuit breakers, transformers, and lightning arresters. However, there may be occasions when these other terminal equipments may be disconnected from the line, and the capacitor will then be left alone at the end of the line without benefit of the protection that any other equipment might provide. For example, a disconnect may be opened between a breaker and the capacitor, or a breaker may be opened between a transformer or an arrester and the capacitor. If such can happen, the capacitor must be able to withstand the voltage that will dash over the line at the point where the capacitor is connected.

Rated Circuit Voltage, kv		Withstand Test Voltages		
			Low Frequency	
Phase-to-Phase	Phase-to-Ground	impulse, kv	Dry 1-Min, kv	Wet 10-Sec, kv
115	66.4	550	265	230
138	79.7	650	320	275
161	93.0	750	370	315
230	133.0	1050	525	445
287	166.0	1300	655	555

Table 4. Standard Withstand Test Voltages for Coupling Capacitors

Some lines are overinsulated, either because they are subjected to unusual insulator contamination or because they are insulated for a future higher voltage than the present operating value. In any event, the capacitor should withstand the actual line flashover voltage unless there is other equipment permanently connected to the line that will hold the voltage down to a lower value.

At altitudes above 3300 feet, the flashover value of air-insulated equipment has decreased appreciably. To compensate for this decrease, additional insulation may be provided for the line and for the other terminal equipment. This may require the next higher standard voltage rating for the coupling capacitor, and it is the practice to specify the next higher rating if the altitude is known to be over 3300 feet.

When a coupling-capacitator potential device is to be purchased for operation at the next standard rated circuit voltage below the coupling-capacitator rating, the manufacturer should be so informed. In such a case, a special auxiliary capacitor will be furnished that will provide normal tap voltage even though the applied voltage is one step less than rated.

This will give the device a rated burden of 120 watts. If a special auxiliary capacitor were not furnished, the rated burden would be about 64% of 150 watts instead of 80%. The foregoing will become evident on examination of equation 2 and on consideration of the fact that each rated insulation class is roughly 80% of the next higher rating.

The foregoing applies also to bushing potential devices, except that sometimes a non-standard transformer unit may be required to get 80% of rated output when the device is operating at the next standard rated circuit voltage below the bushing rating.

COMPARISON OF INSTRUMENT POTENTIAL TRANSFORMERS AND CAPACITANCE POTENTIAL DEVICES

Capacitance potential devices are used for protective relaying only when they are sufficiently less expensive than potential transformers. Potential devices are not as accurate as potential transformers, and also they may have undesirable transient inaccuracies unless they are properly loaded. When a voltage source for the protective relays of a single circuit is required, and when the circuit voltage is approximately 69 kv and higher, coupling-capacitor potential devices are less costly than potential transformers. Savings may be realized somewhat below 69 kv if carrier current is involved, because a potential device coupling capacitor can be used also, with small additional expense, for coupling the carrier-current equipment to the circuit. Bushing potential devices, being still less costly, may be even more economical, provided that the devices have sufficiently high rated burden capacity. However, the main capacitor of a bushing potential device cannot be used to couple carrier-current equipment to a power circuit. When compared on a dollars-per-volt-ampere basis; potential transformers are much cheaper than capacitance potential devices.

When two or more transmission-line sections are connected to a common bus, a single set of potential transformers connected to the bus will generally have sufficient capacity to supply the protective-relaying equipments of all the lines, whereas one set of capacitance potential devices may not. The provision of additional potential devices will quickly nullify the difference in cost. In view of the foregoing, one should at least consider bus potential transformers, even for a single circuit, if there is a likelihood that future requirements might involve additional circuits.

Potential transformers energized from a bus provide a further slight advantage where protective-relaying equipment is involved in which dependence is placed on “memory action” for reliable operation. When a line section protected by such relaying equipment is closed in on a nearby fault, and if potential transformers connected to the bus are involved, the relays will have had voltage on them before the line breaker was closed, and hence the memory action can be effective. If the voltage source is on the line side of the breaker, as is usually true with capacitance potential devices, there will have been no voltage on the relays initially, and memory action will be ineffective. Consequently, the relays may not operate if the voltage is too low owing to the presence of a metallic fault with no arcing, thereby requiring back-up relaying at other locations to clear the fault from the system. However, the likelihood of the voltage being low enough to prevent relay operation is quite remote, but the relays may be slow.

Some people object to bus potential transformers on the basis that trouble in a potential transformer will affect the relaying of all the lines connected to the bus. This is not too serious an objection, particularly if the line relays are not allowed to trip on loss of voltage during normal load, and if a voltage-failure alarm is provided.

Where ring buses are involved, there is no satisfactory location for a single set of bus potential transformers to serve the relays of all circuits. In such cases, capacitance potential devices on the line side of the breakers of each circuit are the best solution when they are cheaper.

THE USE OF LOW-TENSION VOLTAGE

When there are step-down power transformers at a location where voltage is required for protective-relaying equipment, the question naturally arises whether the relay voltage can be obtained from the low-voltage side of the power transformers, and thereby avoid the expense of a high-voltage source. Such a low-voltage source can be used under certain circumstances.

The first consideration is the reliability of the source. If there is only one power transformer, the source will be lost if this power transformer is removed from service for any reason. If there are two or more power transformers in parallel, the source is probably sufficiently reliable if the power transformers are provided with separate breakers.

The second consideration is whether there will be a suitable source for polarizing directional-ground relays if such relays are required. If the power transformers are wye delta, with the high-voltage side connected in wye and the neutral grounded, the neutral current can be used for polarizing. Of course, the question of whether a single power transformer can be relied on must be considered as in the preceding paragraph. If the high-voltage side is not a grounded wye, then a high-voltage source must be provided for directional-ground relays, and it may as well be used also by the phase relays.

Finally, if distance relays are involved, the desirability of “transformer-drop compensation” must be investigated. This subject will be treated in more detail when we consider the subject of transmission-line protection.

The necessary connections of potential transformers for obtaining the proper voltages for distance relays will be discussed later. Directional-overcurrent relays can use any conventional potential-transformer connection.

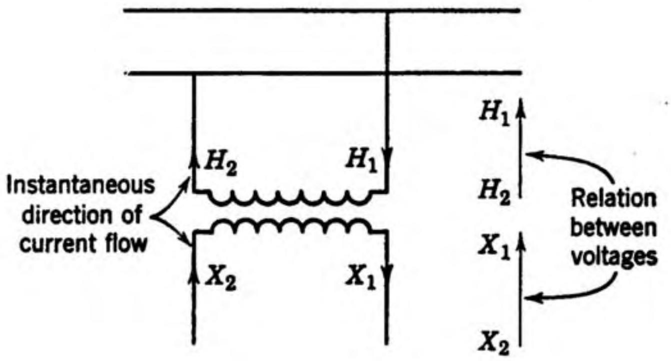

Instantaneous direction of current flow
H_2
H_1
X_2
X_1
H_1
H_2
X_1
X_2
Relation between voltages

Fig. 6. Significance of potential-transformer polarity marks.

POLARITY AND CONNECTIONS

The terminals of potential transformers are marked to indicate the relative polarities of the primary and secondary windings. Usually, the corresponding high-voltage and low-voltage terminals are marked “H1” and “X1,” respectively (and “ Y1” for a tertiary). In capacitance potential devices, only the X1 and Y1 terminals are marked, the H1 terminal being obvious from the configuration of the equipment.

The polarity marks have the same significance as for current transformers, namely, that, when current enters the H1 terminal, it leaves the X1 (or Y1) terminal. The relation between the high and low voltages is such that X1 (or Y1) has the same instantaneous polarity as H1, as shown in Fig. 6. Whether a transformer has additive or subtractive polarity may be ignored because it has absolutely no effect on the connections.

Distance relays for interphase faults must be supplied with voltage corresponding to primary phase-to-phase voltage, and any one of the three connections shown in Fig. 7 may be used. Connection A is chosen when polarizing voltage is required also for directional ground relays; this will be discussed later in this chapter. The equivalent of connection A is the only one used if capacitance potential devices are involved. Connections B and C do not provide means for polarizing directional-ground relays; of these two, connection C is the one generally used because it is less expensive since it employs only two potential transformers. The burden on each potential transformer is less in connection B, which is the only reason it would ever be chosen.

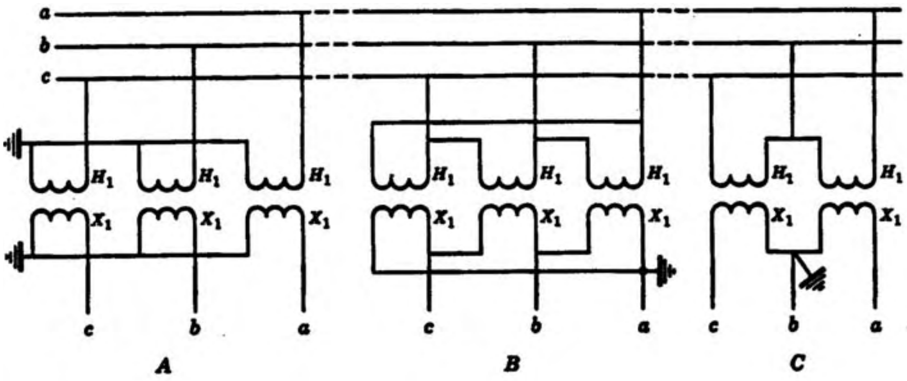


Fig. 7. Connections of potential transformers for distance relays.

The voltages between the secondary leads for all three connections of Fig. 7 are the same, and in terms of symmetrical components are:

$$
\begin{aligned}
V_{ab} &= V_a - V_b \\
&= V_{a1} + V_{a2} + V_{a0} - V_{b1} - V_{b2} - V_{b0} \\
&= (1 - a^2)\ V_{a1} + (1 - a)\ V_{a2} \\
&= (\tfrac{3}{2} + j\sqrt{3}/2)\ V_{a1} + (\tfrac{3}{2} - j\sqrt{3}/2)\ V_{a2}
\end{aligned}
$$

Similarly,

$$
\begin{aligned}
V_{bc} &= (1 - a^2)\ V_{b1} + (1 - a)\ V_{b2} \\
&= a^2(1 - a^2)\ V_{a1} + a(1 - a)\ V_{a2} \\
&= (a^2 - a)\ V_{a1} + (a - a^2)\ V_{a2} \\
&= -j\sqrt{3}\ V_{a1} + j\sqrt{3}\ V_{a2} \\
V_{ca} &= (1 - a^2)\ V_{c1} + (1 - a)\ V_{c2} \\
&= a(1 - a^2)\ V_{a1} + a^2(1 - a)\ V_{a2} \\
&= (a - 1)\ V_{a1} + (a^2 - 1)\ V_{a2} \\
&= (-\tfrac{3}{2} + j\sqrt{3}/2)\ V_{a1} + (-\tfrac{3}{2} - j\sqrt{3}/2)\ V_{a2}
\end{aligned}
$$

LOW-TENSION VOLTAGE FOR DISTANCE RELAYS

The potential transformers must be connected to the low-voltage source in such a way that the phase-to-phase voltages on the high-voltage side will be reproduced. The connection that must be used will depend on the power-transformer connections. If, as is not usually the case, the power-transformer bank is connected wye-wye or delta-delta, the potential transformer connections would be the same as though the potential transformers were on the high-voltage side. Usually, however, the power transformers are connected wye-delta or delta-wye.

First, let us become acquainted with the standard method of connecting wye-delta or delta-wye power transformers. Incidentally, in stating the connections of a power-transformer bank, the high-voltage connection is stated first; thus a wye-delta transformer bank has its high-voltage side connected in wye, etc. The standard method of connecting power transformers does not apply to potential transformers (which are connected as required), but the technique involved in making the desired connections will apply also to potential transformers.

The standard connection for power transformers is that, with balanced three-phase load on the transformer bank, the current in each phase on the high-voltage side will lead by 30° the current in each corre-

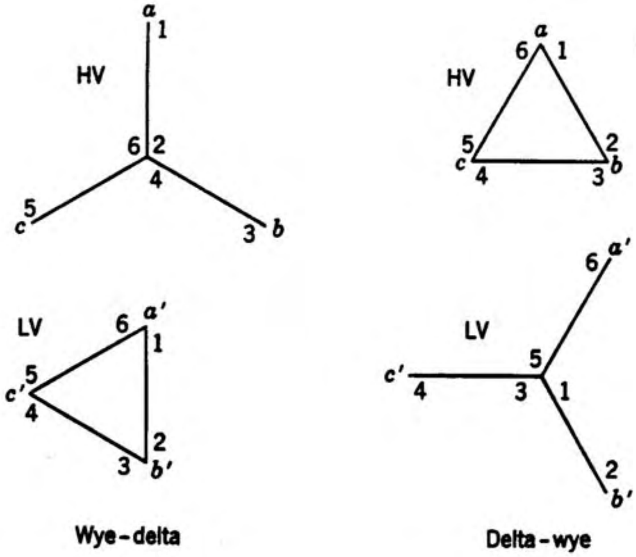


Fig. 8. Three-phase voltages for standard connection of power transformers.

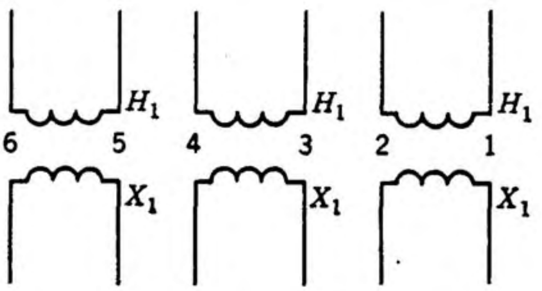


Fig. 9. Numbering the ends of the transformer windings preparatory to making three-phase connections.

sponding phase on the low-voltage side. Also, the no-load phase-to-phase voltages on the high-voltage side will lead the corresponding low-voltage phase-to-phase voltages by 30°. For this to be true, the three-phase voltages must be as in Fig. 8, where a' corresponds to a, b' to b, and c' to c. The numbers on the voltage vectors of Fig. 8 designate the corresponding ends of the transformer windings, 1-2 designating the primary and secondary windings of one transformer, etc. Now, consider three single-phase transformers as in Fig. 9 with their primary and secondary windings designated 1-2, etc. If we assume that the transformers are rated for either phase-to-phase or phase-to ground connection, it is only necessary to connect together the numbered ends that are shown connected in Fig. 8, and the connections of Fig. 10 will result.

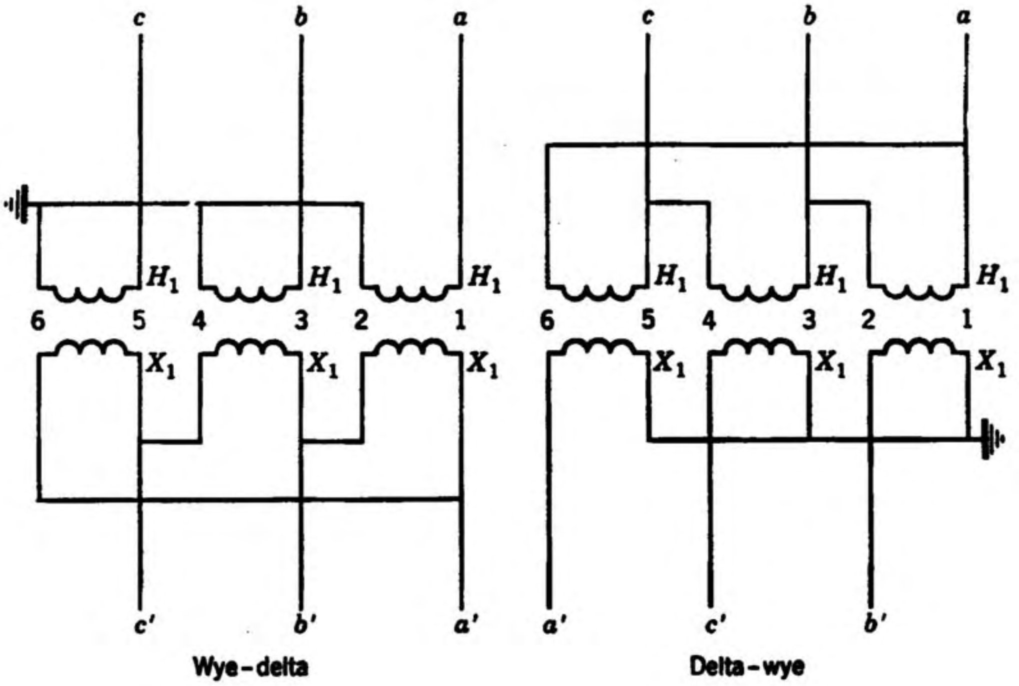


Fig. 10. Interconnecting the transformers of Fig. 9 according to Fig. 8 to get standard connections.

We can now proceed to examine the connections of potential transformers on the low-voltage side that are used for the purpose of supplying voltage to distance relays. Figure 11 shows the connections if the power transformers are connected wye-delta. Figure 12 shows the connections if the power transformers are connected delta-wye.

For either power-transformer connection, the phase-to-phase voltages on the secondary side of the potential transformers will contain the same phase-sequence components as those derived for the connections of Fig. 7, if we neglect the voltage drop or rise owing to load or fault currents that may flow through the power transformer. If, for one reason or another, the potential transformers must be connected delta-delta or wye-wye, or if the voltage magnitude is incorrect, auxiliary potential transformers must be used to obtain the required voltages for the distance relays.

The information given for making the required connections for distance relays should be sufficient instruction for making any other desired connections for phase relays. Other application considerations involved in the use of low-voltage sources for distance and other relays will be discussed later.

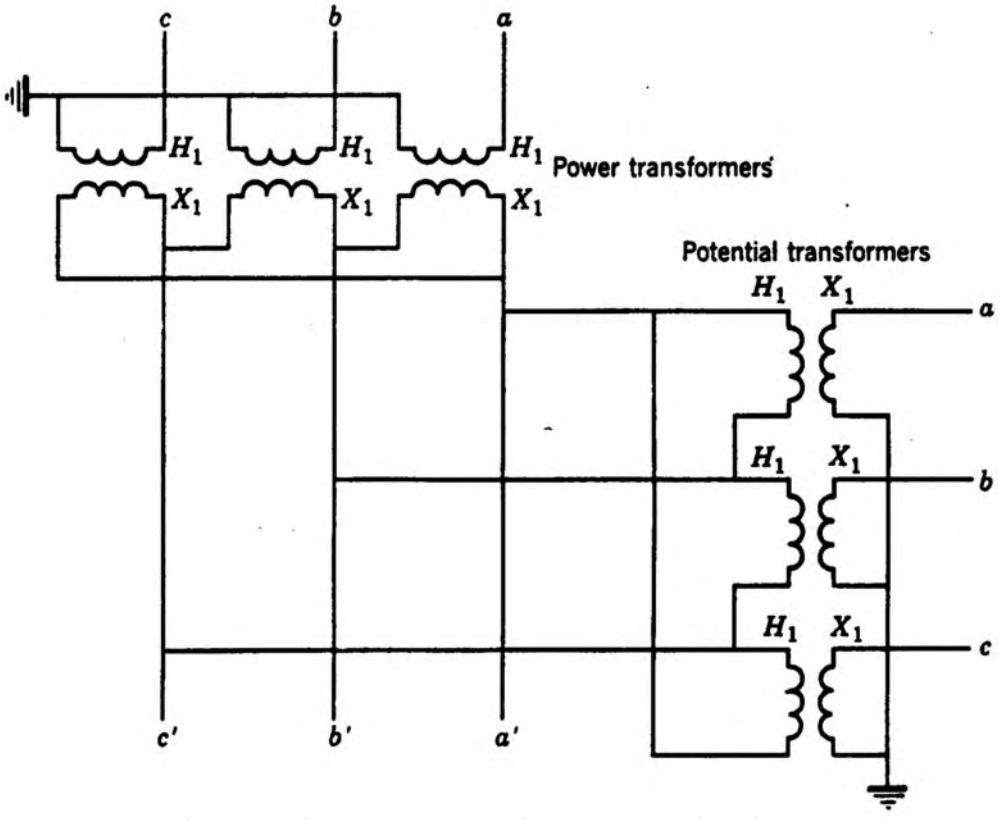


Fig. 11. Connections of potential transformers on low-voltage side of wye-delta power transformer for use with distance relays.

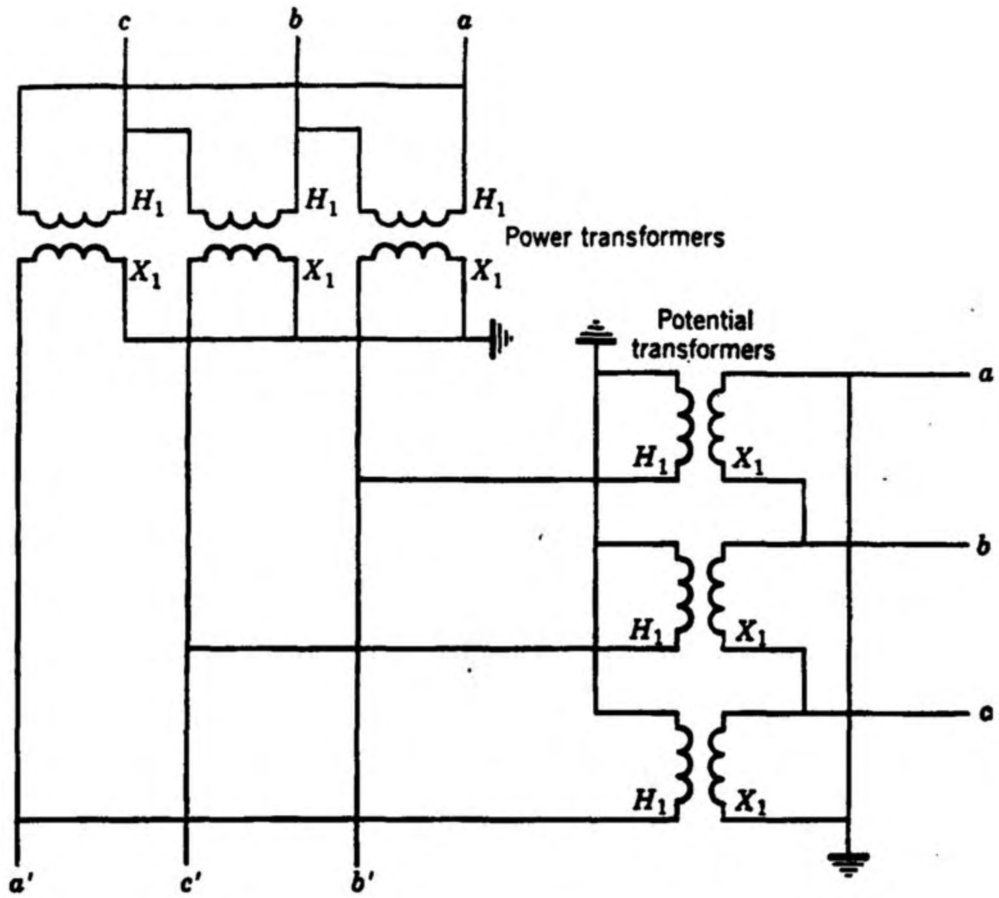


Fig. 12. Connections of potential transformers on low-voltage side of delta-wye power transformer for use with distance relays.

CONNECTIONS FOR OBTAINING POLARIZING VOLTAGE FOR DIRECTIONAL-GROUND RELAYS

The connections for obtaining the required polarizing voltage are shown in Fig. 13. This is called the "broken-delta" connection. The voltage that will appear across the terminals nm is as follows:

$$
\begin{aligned}
V_{nm} &= V_a + V_b + V_c \\
&= (V_{a1} + V_{a2} + V_{a0}) + (V_{b1} + V_{b2} + V_{b0}) + (V_{c1} + V_{c2} + V_{c0}) \\
&= V_{a0} + V_{b0} + V_{c0} = 3V_{a0} = 3V_{b0} = 3V_{c0}
\end{aligned}
$$

In other words, the polarizing voltage is 3 times the zero-phase-sequence component of the voltage of any phase.

The actual connections in a specific case will depend on the type of voltage transformer involved and on the secondary voltage required for other than ground relays. If voltage for distance relays must also be supplied, the connections of Fig. 14 would be used.

If voltage is required only for polarizing directional-ground relays, three coupling capacitors and one potential device, connected as in Fig. 15 would suffice. The voltage obtained from this connection is 3 times the zero-phase-sequence component.

The connection of Fig. 15 cannot always be duplicated with bushing potential devices because at least some of the capacitance corresponding to the auxiliary capacitor C2 might be an integral part of the bushing and could not be separated from it. The capacitance to ground of interconnecting cable may also have a significant effect.

The three capacitance tape may be connected together, and a special potential device may be connected across the tap voltage as shown in Fig. 16, but the rated burden may be less than that of Table 1.

Incidentally, a capacitance bushing cannot be wed to couple carrier current to a line because there is no way to insert the required carrier-current choke coil in series with the bushing capacitance between the tap and ground, to prevent short-circuiting the output of the carrier-current transmitter.

PROBLEM

1. Given a wye-delta power transformer with standard connections. According to the definitions of this section, draw the connection diagram and the three-phase voltage vector diagram for the HV and the LV sides, labeling the HV phases a, b, and c and the corresponding LV phases a', b' and c', (1) for positive-phase-sequence voltage applied to the HV side, and (2) for negative-phase-sequence voltage applied to the HV side. When positive-phase-sequence voltage is applied to the HV side, the phase sequence is a-b-c.

When negative voltage is applied, there is no change in connections, but the phase sequence is a-c-b.

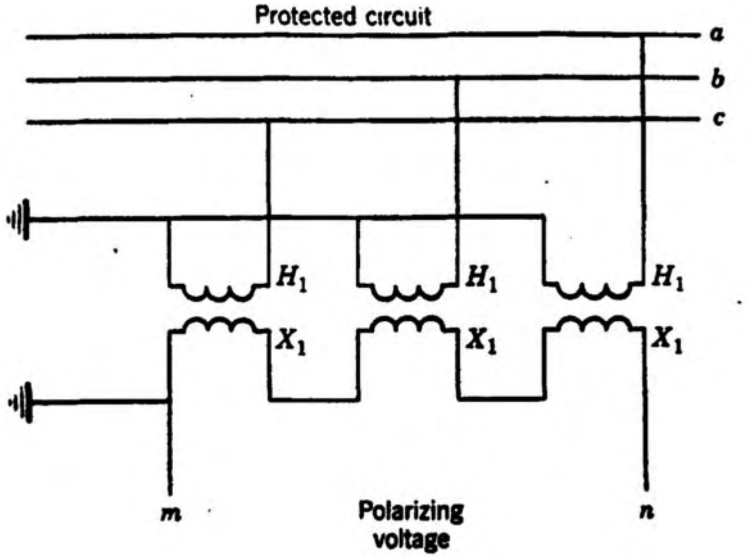


Fig. 13. The broken-delta connection.

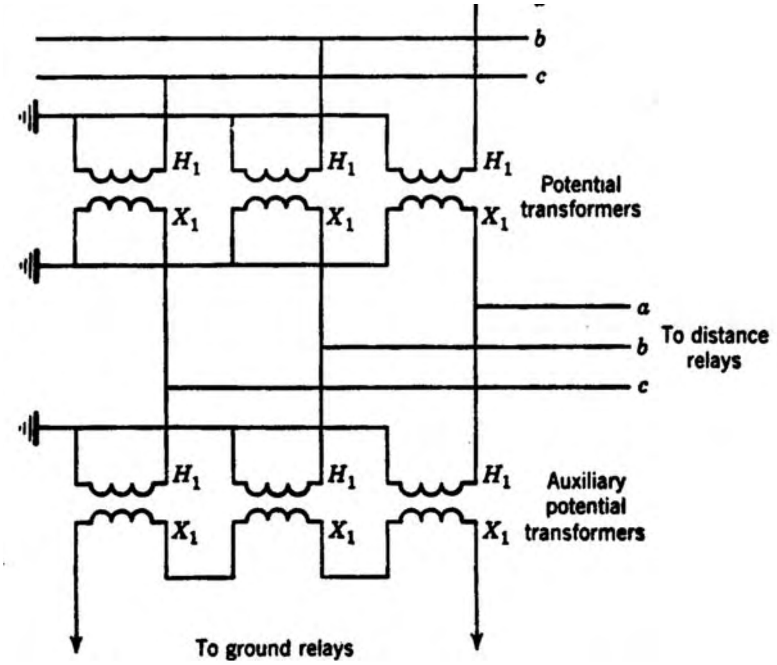


Fig. 14. Potential-transformer connections for distance and ground relays.

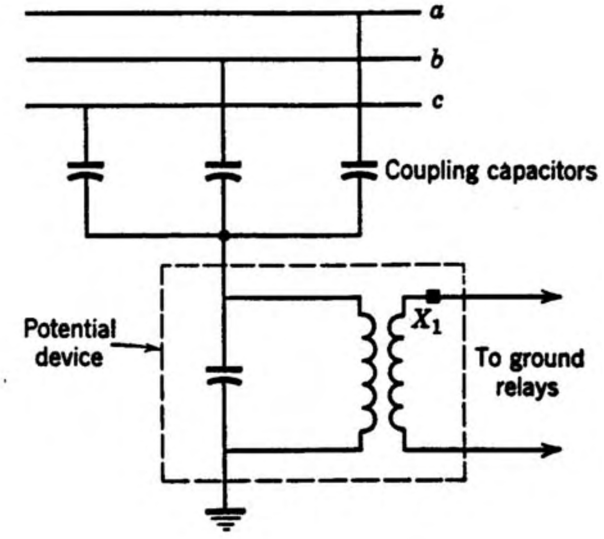


Fig. 15. Connection of three coupling capacitors and one potential device for providing polarizing voltage for directional-ground relays.

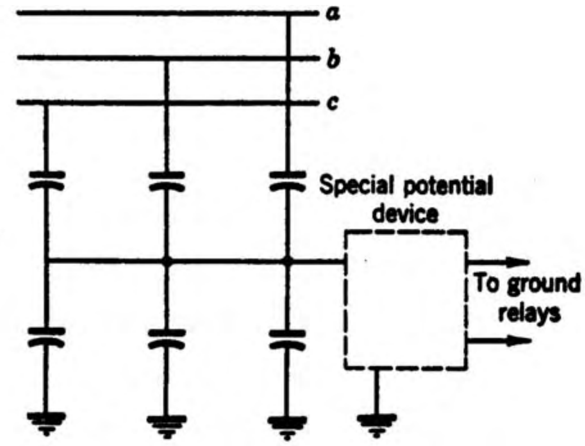


Fig. 16. Use of one potential device with three capacitance bushings.

CASE STUDIES REGARDING THE INTEGRATION OF MONITORING & DIAGNOSTIC EQUIPMENT ON AGING TRANSFORMERS WITH COMMUNICATIONS FOR SCADA AND MAINTENANCE

Byron Flynn, Application Engineer, GE Energy

I. ABSTRACT

Valuable information from Monitoring and Diagnostics (M&D) equipment installed on aging power transformers helps utility personnel operate and maintain critical infrastructure.

M&D systems provide valuable on-line information from power transformers including gas in oil, internal hot spot temperature, insulation aging moisture content in winding insulation, bubbling temperature, and OLTC position tracking. This article reviews several methods of integrating M&D equipment to provide this information to SCADA and maintenance systems.

II. BACKGROUND

A discussion of Transformer Monitoring and Diagnostics has a basis on the fundamental construction of a transformer. The transformer is basically a machine consisting of several parts: This discussion, while seemingly overly simplistic, is useful to provide a basis of failure modes and monitoring and diagnostic methods.

The core and coil are the fundamental components of a transformer providing the coupling of magnetic flux between two windings. The core and coils are placed in a tank filled with oil and connected to bushings. The cooling system and control

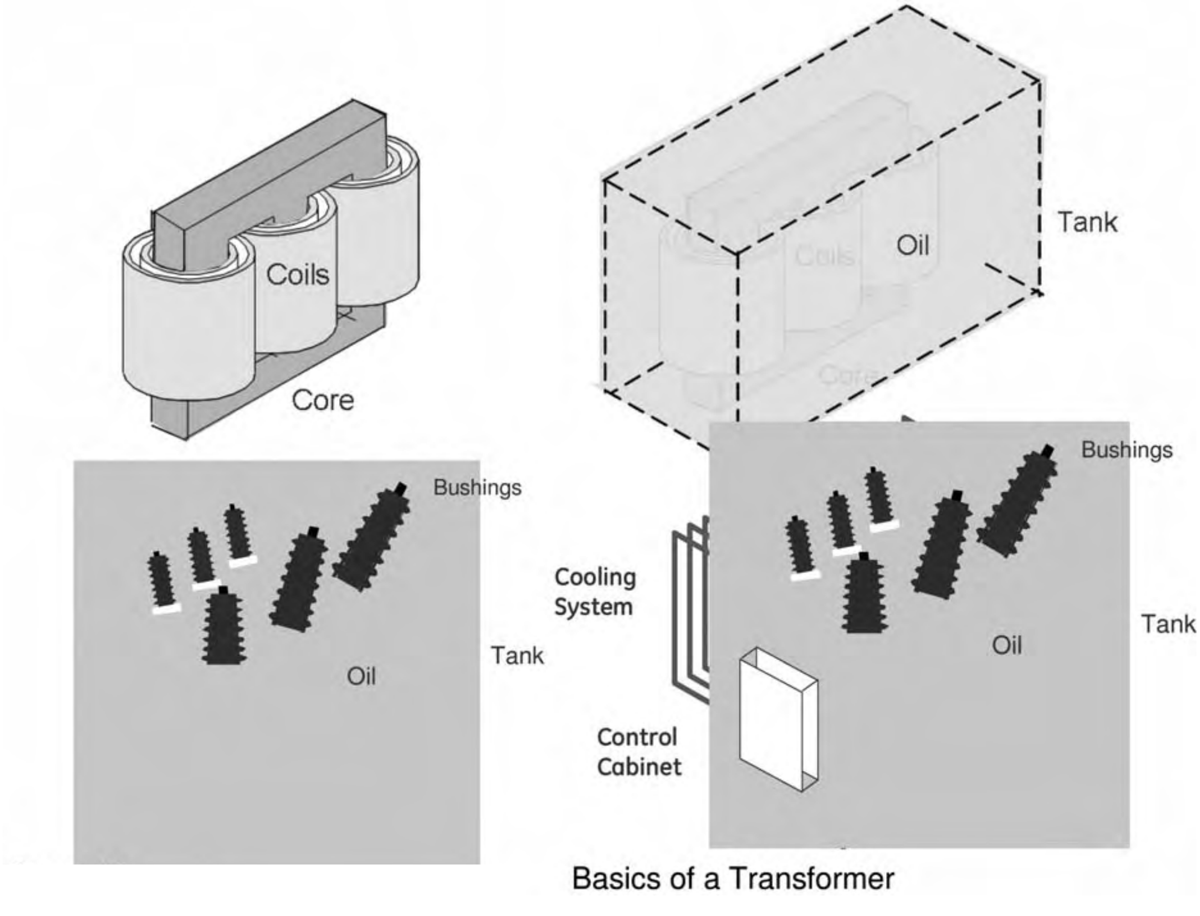


Figure 1

cabinet are the remaining fundamental components of a transformer. Additionally, many transformers in distribution substations include a Load Tap Changer (LTC) that provides additional voltage control on the distribution feeder.

There have been significant efforts to understand the various failure modes of power transformers. Applying the fundamentals of an FMEA analysis consisting of:

- Identify functions
- Identify failure modes
- Identify failure causes
- Identify effects of failure modes
- Identify criticality or risk
- Select on-line monitoring to match characteristic of developing failure cause(s)

The analysis of the failure modes of the various components then leads to a review of the inspection and maintenance procedures of power transformers. Then applying Reliability Center Maintenance (RCM) tools to the failure mode analysis information helps a utility design a monitoring system to optimize utilization and eventual life cycle.

Preventive and predictive maintenance:
Reduces the risk and costs of unexpected failure
Actual conditions drive maintenance and repair
Extending life of assets
Reducing costs of maintenance

On-Line diagnostic condition assessment addressing common failure modes:
Multiple sensors
Multiple on-line models
All parameters are recorded automatically and continuously Trend and limit alarms

ON-LINE DIAGNOSTICS MODELS

To deal with the potential overload of data, many utilities are installing systems with online diagnostics models. These models were installed to reduce the flood of raw data and to continuously provide information regarding the transformer health and operating history. Additionally, the Dynamic Loading Model provides a guide which can assist the dispatchers by calculating the overloading capabilities based on current operating conditisions, especially useful during critical times.

Additionally, early detection of problems, at the incipient stage, will help extend the life of the transformers. Detection of these problems is accomplished with several models which rely on various sensors installed on the transformer and in the substation, combined with other parameters manually entered. This data is then fed into industry standard and accepted models, which calculate the various outputs. These outputs are displayed and trended in the two Master Stations. These capabilities increase the useful data while significantly reducing the shear volume of data. The models focused on the main tank, the LTC and the cooling system and will be described briefly in this section. [1] & [2].

LOAD CURRENT MODEL

The first two models use routine calculations. The Load Current Model calculates average and maximum current on each winding based on one-second measurements.

This data is available for display and for trending in the Master Stations. The model's block diagram is shown below.

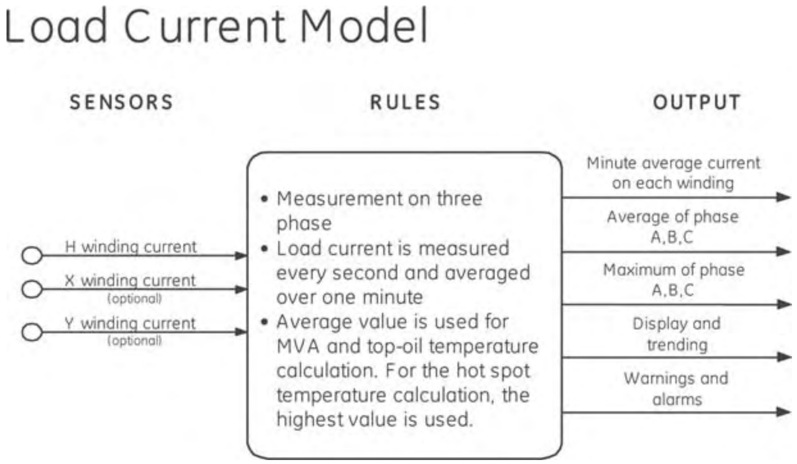

Load Current Model
SENSORS
RULES
OUTPUT
H winding current
X winding current (optional)
Y winding current (optional)
• Measurement on three phase
• Load current is measured every second and averaged over one minute
• Average value is used for MVA and top-oil temperature calculation. For the hot spot temperature calculation, the highest value is used.
Minute average current on each winding
Average of phase A,B,C
Maximum of phase A,B,C
Display and trending
Warnings and alarms

Figure #2: Load Current Model

APPARENT POWER MODEL

The Apparent Power Model simply calculates average apparent power (MVA) from the transformers' current and voltage. The average and maximum MVA readings are then displayed and trended. Warnings and alarms are also provided, if limits are reached.

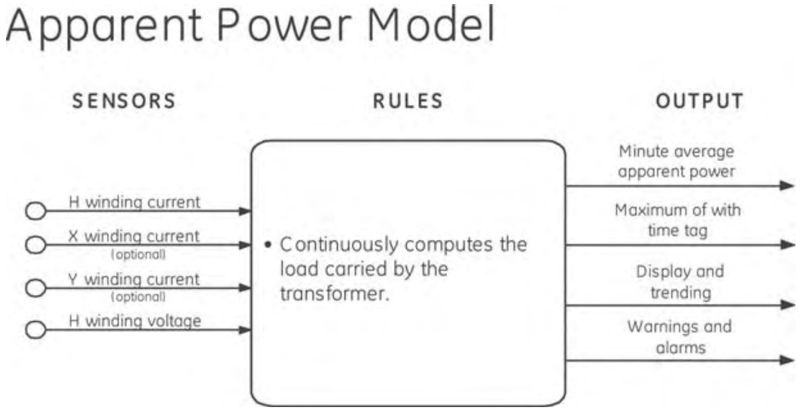

Apparent Power Model
SENSORS
RULES
OUTPUT
H winding current
X winding current (optional)
Y winding current (optional)
H winding voltage
• Continuously computes the load carried by the transformer.
Minute average apparent power
Maximum of with time tag
Display and trending
Warnings and alarms

Figure #3: Apparent Power Model

WINDING TEMPERATURE MODEL

The Winding Temperature Model is based on IEEE and IEC loading guides. In accordance with these guides, it calculates the hottest spot temperature on each winding. The values are then made available for trend and display on the master stations. The following block diagram illustrates this model's inputs and outputs.

Computations are carried out according to:

- IEC 354, Loading Guide for Oil-Immersed Power Transformers, Section 2.4, Equation 1
- IEEE C57.91-1995/Cor 1/ July, 2001 Guide for

Loading Mineral-Oil-Immersed Transformers, Section 7.2.6, Equation 16, 17, 18

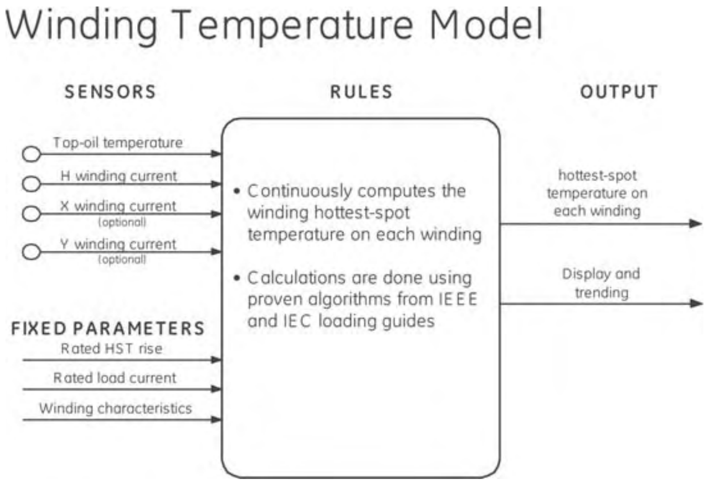

Winding Temperature Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
FIXED PARAMETERS
Rated HST rise
Rated load current
Winding characteristics
• Continuously computes the winding hottest-spot temperature on each winding
• Calculations are done using proven algorithms from IEEE and IEC loading guides
hottest-spot temperature on each winding
Display and trending

Figure #4: Winding Temperature Model

INSULATION AGING MODEL

The Insulation Aging Model calculates transformer aging data based on two different methods, daily & cumulative (IEEE + IEC). The computations are carried out according to:

• IEC 354, Loading Guide for Oil-Immersed Power Transformers; Section 2.6.2,

Equation 7, 8

• IEEE C57.91-1995/Cor 1/ July, 2001 Guide for Loading Mineral-Oil-Immersed Transformers; Section 5.2, Equation 2 for 65°C thermally upgraded paper; Annex D, Equation D2 for 55°C normal Kraft paper.

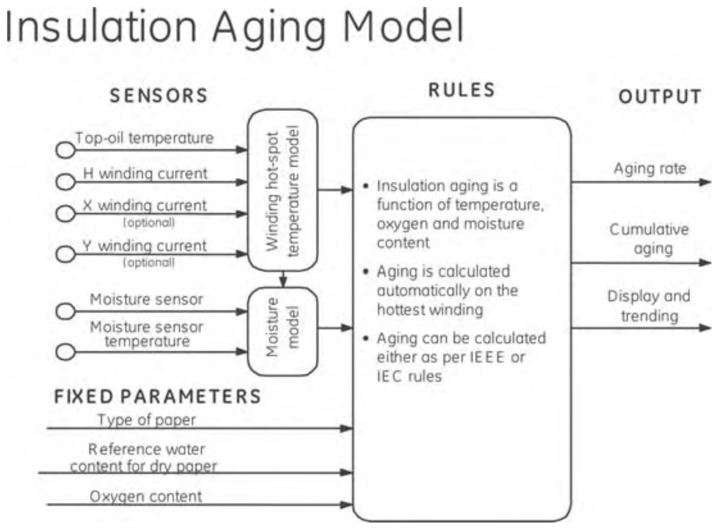
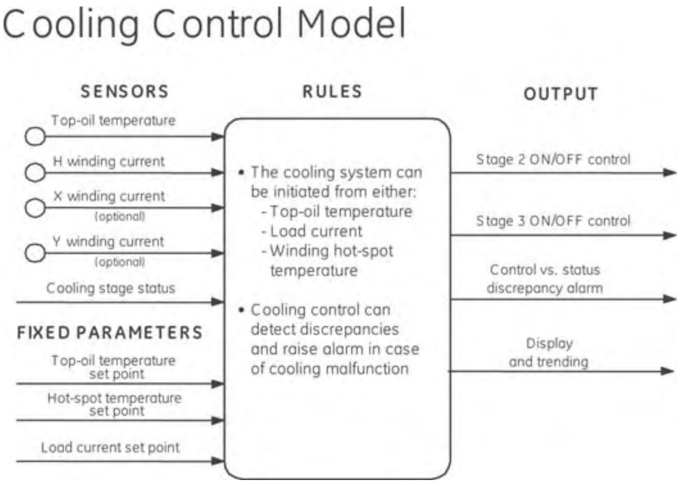

Insulation Aging Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
Moisture sensor
Moisture sensor temperature
Winding hot-spot temperature model
Moisture model
FIXED PARAMETERS
Type of paper
Reference water content for dry paper
Oxygen content
• Insulation aging is a function of temperature, oxygen and moisture content
• Aging is calculated automatically on the hottest winding
• Aging can be calculated either as per IEEE or IEC rules
Aging rate
Cumulative aging
Display and trending

Figure #5: Insulation Aging Model

COOLING CONTROL MODEL

The system also can be used for cooling control using the model described in the block diagram below. The system is used as a backup.


Cooling Control Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
Cooling stage status
FIXED PARAMETERS
Top-oil temperature set point
Hot-spot temperature set point
Load current set point
• The cooling system can be initiated from either:
- Top-oil temperature
- Load current
- Winding hot-spot temperature
• Cooling control can detect discrepancies and raise alarm in case of cooling malfunction
Stage 2 ON/OFF control
Stage 3 ON/OFF control
Control vs. status discrepancy alarm
Display and trending

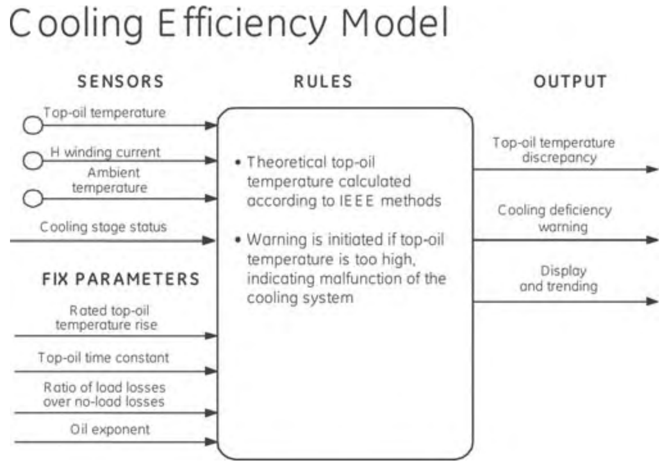
COOLING EFFICIENCY

The Cooling Efficiency Model is used to determine if the Cooling system can lose efficiency over time due to fan failure, physical failure or coolers clogged with pollen, dirt, or nests. These conditions need to be detected before a transformer overload occurs. The model uses the following calculation methods:

• IEC 354, Loading Guide for Oil-Immersed Power Transformers; Section 2.4.1,

Equation 1

• IEEE C57.91-1995/Cor 1/ July, 2001 Guide for Loading Mineral-Oil-Immersed Transformers; Section 7.2.4, Equations 8, 9, 10, 11, 15

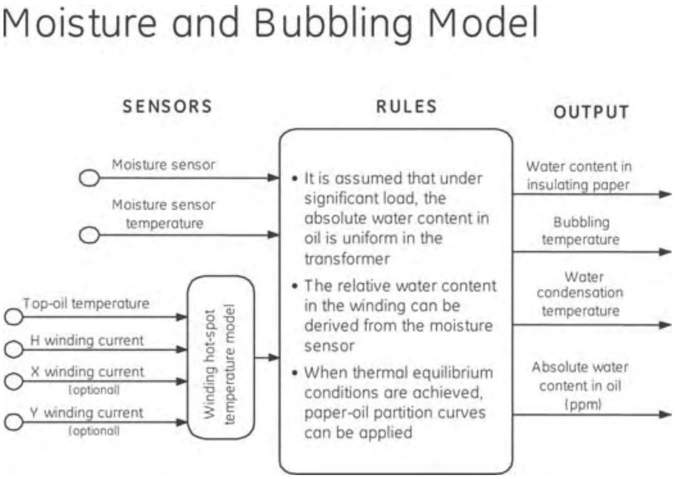

Cooling Efficiency Model
SENSORS
RULES
OUTPUT
Top-oil temperature
H winding current
Ambient temperature
Cooling stage status
FIX PARAMETERS
Rated top-oil temperature rise
Top-oil time constant
Ratio of load losses over no-load losses
Oil exponent
• Theoretical top-oil temperature calculated according to IEEE methods
• Warning is initiated if top-oil temperature is too high, indicating malfunction of the cooling system
Top-oil temperature discrepancy
Cooling deficiency warning
Display and trending

MOISTURE AND BUBBLING MODEL

Moisture content of paper is critical because it reduces dielectric strength and increases risk of bubbling at high load resulting in accelerates. The calculations are carried out in line with the following recommended methods:

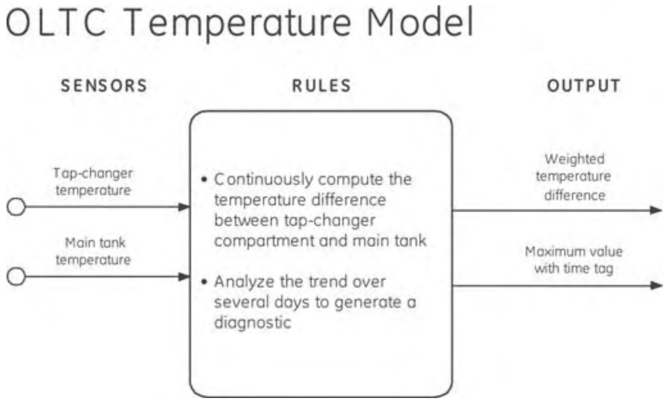
• T.V. Oommen, “Moisture Equilibrium in Paper-Oil Insulation Systems”, Proc. Electrical Insulation Conference, Chicago, October 1983

- W.J. McNutt, G.H. Kaufmann, A.P. Vitols and J.D. MacDonald, “Short-Time Failure Mode Considerations Associated With Power Transformer Overloading”, IEEE Trans. PAS, Vol. PAS-99, No. 3, May/June 1980
- T.V. Oommen, E.M. Petrie and S.R. Lindgren, “Bubble Generation in Transformer Windings Under Overload Conditions”, Doble Client Conference, Boston, 1995
- V.G. Davydov, O.M. Roizman and W.J. Bonwick, “Transformer Insulation Behavior During Overload”, EPRIÒ Substation Equipment Diagnostic Conference V, New Orleans, February 1997


Moisture and Bubbling Model
SENSORS
RULES
OUTPUT
Moisture sensor
Moisture sensor temperature
Top-oil temperature
H winding current
X winding current (optional)
Y winding current (optional)
Winding hot-spot temperature model
• It is assumed that under significant load, the absolute water content in oil is uniform in the transformer
• The relative water content in the winding can be derived from the moisture sensor
• When thermal equilibrium conditions are achieved, paper-oil partition curves can be applied
Water content in insulating paper
Bubbling temperature
Water condensation temperature
Absolute water content in oil (ppm)

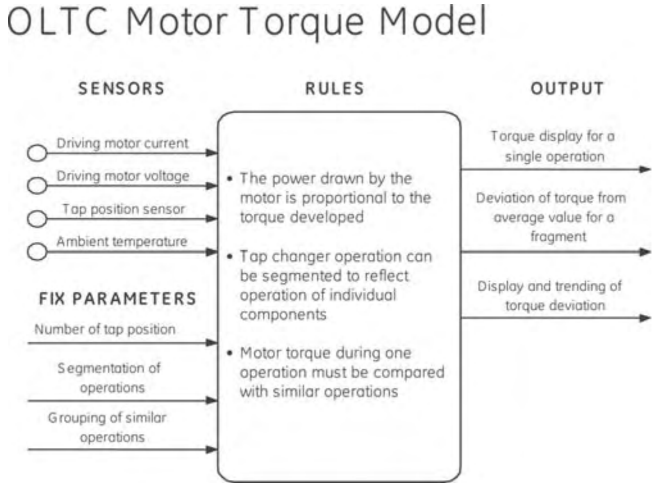
TAP CHANGER TEMPERATURE MODEL

Over the life of the transformer, the Tap Changer is a significant source of potential maintenance issues. Many problems with the tap-changer (contact coking) lead to temperature rise in the tap-changer compartment. This failure mode is easily detected by monitoring tap-changer temperature compared to main tank temperature.


OLTC Temperature Model
SENSORS
RULES
OUTPUT
Tap-changer temperature
Main tank temperature
• Continuously compute the temperature difference between tap-changer compartment and main tank
• Analyze the trend over several days to generate a diagnostic
Weighted temperature difference
Maximum value with time tag

TAP CHANGER MOTOR TORQUE MODEL

A change in the motor torque pattern is another indicator of mechanical failures of a tapchanger component. The Tap Changer Motor Torque Model provides a means of detecting a fault in the tap changer, the reversing selector, the gears or energy storage device.

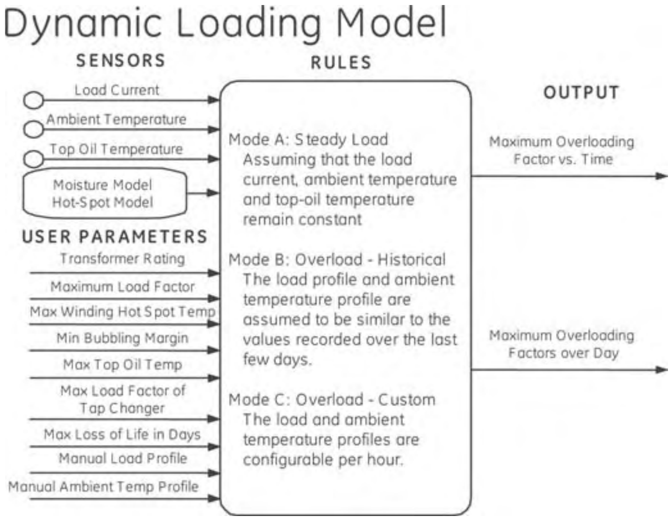

OLTC Motor Torque Model
SENSORS
RULES
OUTPUT
Driving motor current
Driving motor voltage
Tap position sensor
Ambient temperature
FIX PARAMETERS
Number of tap position
Segmentation of operations
Grouping of similar operations
• The power drawn by the motor is proportional to the torque developed
• Tap changer operation can be segmented to reflect operation of individual components
• Motor torque during one operation must be compared with similar operations
Torque display for a single operation
Deviation of torque from average value for a fragment
Display and trending of torque deviation

DYNAMIC LOADING MODEL

The Dynamic Loading Model provides the operators with a perspective of the overloading capabilities, based on its current operating conditions. As the load grows in the area, this capability will become more critical in the operation of the transformer.

The Dynamic Loading Model is based on the following models:

- IEC 354, Section 2.4
- IEEE C57.91-1995, Section 5.2 & 7.2.6


Dynamic Loading Model
SENSORS
RULES
OUTPUT
Load Current
Ambient Temperature
Top Oil Temperature
Moisture Model
Hot-Spot Model
USER PARAMETERS
Transformer Rating
Maximum Load Factor
Max Winding Hot Spot Temp
Min Bubbling Margin
Max Top Oil Temp
Max Load Factor of Tap Changer
Max Loss of Life in Days
Manual Load Profile
Manual Ambient Temp Profile
Mode A: Steady Load
Assuming that the load current, ambient temperature and top-oil temperature remain constant
Mode B: Overload - Historical
The load profile and ambient temperature profile are assumed to be similar to the values recorded over the last few days.
Mode C: Overload - Custom
The load and ambient temperature profiles are configurable per hour.
Maximum Overloading Factor vs. Time
Maximum Overloading Factors over Day

III. CASE STUDIES

CASE STUDY #1

Overall System Requirements

1. To gain remote control & monitoring of two Substations
   - By reducing outage times
   - By reducing operating costs
   - By reducing trips to the field

- By catching problems before failures occur
- By maintaining a healthy system.

2. To improve monitoring and load management

- By balancing single phase loads
- By monitoring underground for potential overload conditions
- By managing the transformer loading and
- By monitoring and controlling the voltage levels

3. To accommodate future SCADA System growth and to be expandable throughout the entire electrical system

- Including the remaining substations
- Including other distribution breakers and capacitors

The overall system installed is shown in the architecture drawing in Figure #1. The two dispatch centers communicate with the SCADA system via DNP 3.0 over IP on the SCADA System. Data Concentrators/RTUs were installed in the substations, which communicated with several Intelligent Electrical Devices (IEDs). Additionally, communications equipment was installed to support the initial system. The new communications equipment utilized available channel space on the company digital microwave system.

New Dispatch Centers

The SCADA software was configured nearly identically at the two masters. The only other difference with the two dispatch center systems is the master stations have different IP and DNP addresses. This allowed the two systems to be operated independently. System analog and status changes and control signals are communicated to both masters over the same communication line. This is possible because the system operates over Ethernet communications. This also provided the ability to dispatch for the entire system from either master, providing additional coverage during busy times or a secondary master station if a problem occurs. The similarity of the two Master Stations simplified software configuration of the masters and the RTUs. The communications system will be discussed in further detail in a subsequent section.

Integrated Transformer Monitoring

Two monitoring systems were installed on the two 120 MVA transformers and integrate into the system using DNP 3.0 protocol over IP. The monitoring and diagnostic (M&D) systems contain smart RTUs, which form the foundation for the diagnostic system.

These RTUs integrate data from several sensors and the transformer monitoring IEDs and perform the diagnostic models. These IEDs consist of a LTC monitor, and sensors which monitor combustible gases and moisture of the oil in the main tank. The M&D RTUs then analyze the data using several of the diagnostic models. It is important to operations and maintenance personnel that the transformer monitoring system reduce the amount of raw data provided. All the intelligent models described in the previous section were implanted which provided information regarding the health of the transformers. These models focused on three main areas; the main tank, the cooling system, and the Load Tap Changer (LTC).

CASE STUDY #2

This system utilizes on-line monitoring with no on-line diagnostics. It provides an inexpensive method to capture data from the transformer and assist in off-line diagnosis of transformer problems.

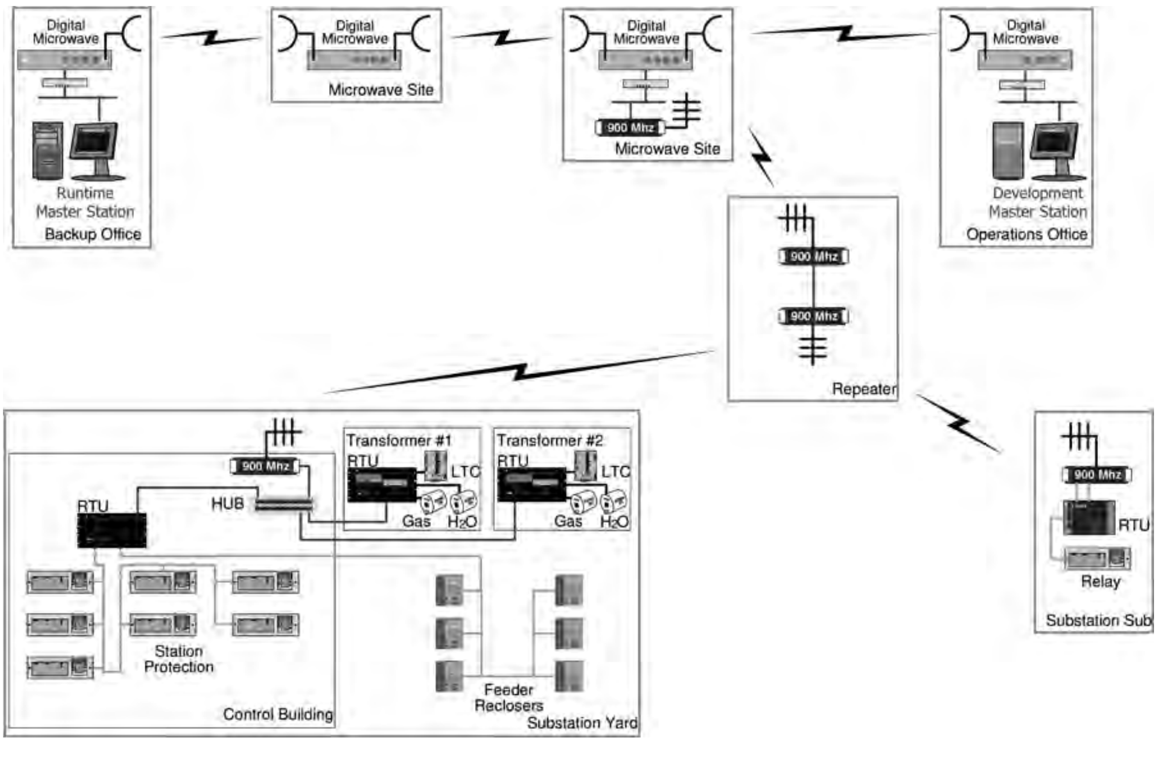


Figure #12: Case #1, System Architecture

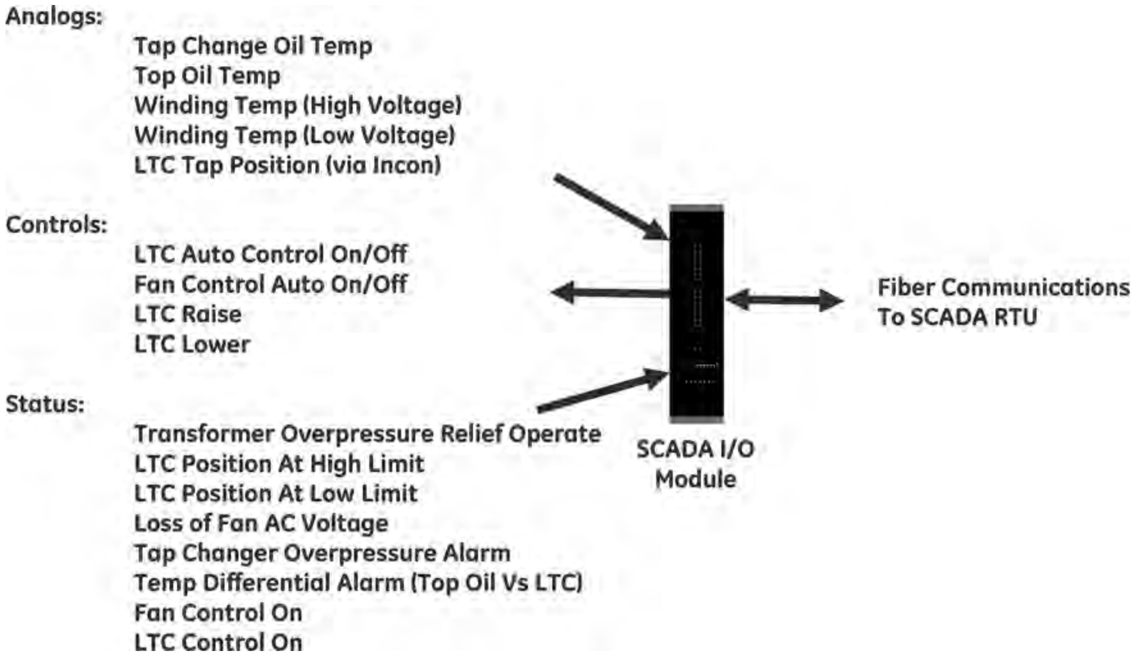

Analogs:
Tap Change Oil Temp
Top Oil Temp
Winding Temp (High Voltage)
Winding Temp (Low Voltage)
LTC Tap Position (via Incon)
Controls:
LTC Auto Control On/Off
Fan Control Auto On/Off
LTC Raise
LTC Lower
Status:
Transformer Overpressure Relief Operate
LTC Position At High Limit
LTC Position At Low Limit
Loss of Fan AC Voltage
Tap Changer Overpressure Alarm
Temp Differential Alarm (Top Oil Vs LTC)
Fan Control On
LTC Control On
SCADA I/O Module
Fiber Communications To SCADA RTU

Figure #13: Case #2, System Architecture

Distributed I/O

This system is based on distributed SCADA I/O modules communicating back to an RTU in the control building. The I/O modules have-on board digital status, analog and control allowing the transformer monitoring system to be integrated into the SCADA system.

Analogs – the following values are used to detect problems with the LTC or the main tank. Additionally, indication of the LTC position is provided which can be used to determine operation of the LTC and potential problems such as LTC hunting or subsequent tracking of the number of operations of each tap between maintenance intervals. These values include:

Tap Change Oil Temperature – to detect problems with the LTC

Top Oil Temperature – can detect problems with the tank or cooling system

Winding Temp (High Voltage)
Winding Temp (Low Voltage)
LTC Tap Position

Controls – provides on/off control of the LTC and Fan automatic systems. In addition, remote control of the LTC is also provided. The points included are:

LTC Auto Control On/Off
Fan Control Auto On/Off
LTC Raise
LTC Lower

Status – The status points monitored include indication of the control points and on other transformer alarm points. The Top Oil vs. LTC temperature alarm is a primary alarm indication of LTC problems whenever the LTC tank temperature exceeds the top oil tank temperature. The status points include:

Transformer Overpressure Relief Operate
LTC Position at High Limit
LTC Position at Low Limit
Loss of Fan AC Voltage
Tap Changer Overpressure Alarm
Temp Differential Alarm (Top Oil Vs LTC)
Fan Control On
LTC Control On

CASE STUDY #3

This system is installed on a power plant Generator Step Up (GSU) transformer. From manual oil samples collected from the transformer, it was found that this GSU was gassing above normal operational parameters. The transformer was taken off line in mid October of 2006 for maintenance. On-Line monitoring is critical for this transformer as failure could result of a loss of revenue exceeding $100K per day.

The customer flushed and filtered the oil and inspected the transformer for any potential problems. A continuous on-line gas PPM monitoring was installed to provide the Power Plant operations indication of combustible gases in the oil.

System Description

This system uses an on-line gas monitor integrated into station RTU which feeds data to the DCS system using Modbus over IP. The on-line gas monitor reports the following data:

- PPM value of composite combustible gas measurement
- Short term and long term rate of change of PPM value of composite combustible gas measurement
- Relative saturation (humidity) of moisture dissolved in oil (%RH)
- Hourly average of %RH and PPM of water in oil
- Computes the PPM water content in oil
- Computes the water in oil condensation temperature

Monitoring these parameters at the plant will help reduce the potential of an unexpected outage due to failure of the transformer.

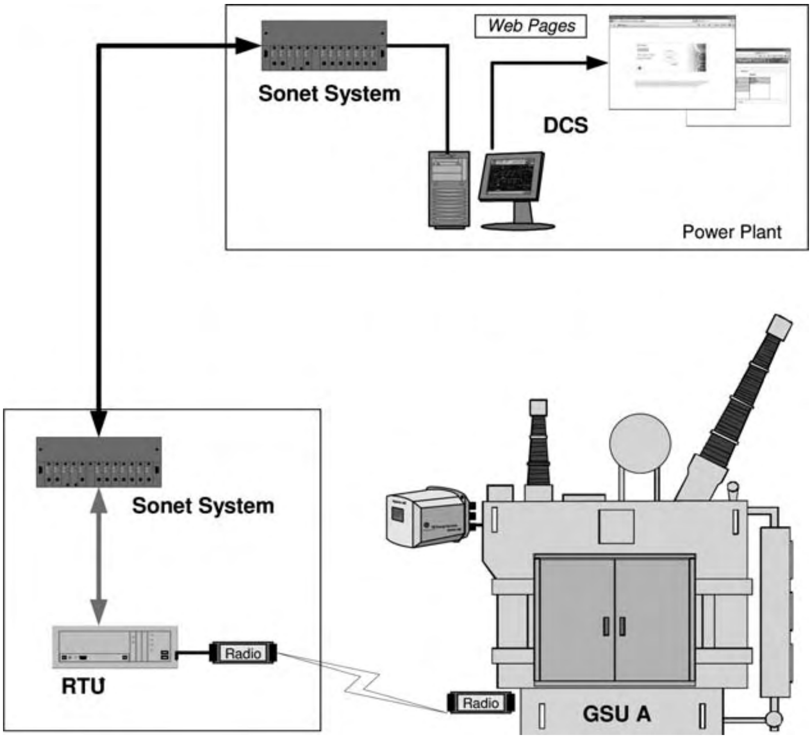


Figure #14: Case #3, System Architecture

CASE STUDY #4

This system is installed at another utility on a series of power plant Generator Step Up (GSU) transformers. This utility had similar concerns about the potential revenue lost from unexpected GSU failure. Much of their fleet of GSU transformers are over 30 years old. This utility also was looking for a method of reducing maintenance costs and loading on limited maintenance resources by moving to a condition based maintenance system. On-Line diagnostics was installed to provide real time information to the plant control operators on their DCS systems and to their SCADA system.

System Description

This system uses an on-line diagnostic system integrated into station DCS using Modbus over IP. All the diagnostic models described in Section II were installed and integrated into the DCS critical data was also provided to the SCADA system via web pages from the DCS system. The on-line diagnostics system was installed because the models reduced the amount of raw data being handled by the operators and the value of calculated output data which then generates an alarm when the model detects a problem. Over 150 gas monitors and 40 diagnostic systems have been installed to date, the utility plans to install an additional 40 units over the next three years.

CASE STUDY #5

This case study describes a system installed on two large 400MVA station transformers.

The utility decided to install a diagnostic system because of the critical nature of these transformers and the costs of an unexpected failure. The diagnostics systems for these transformers, shown in the photos in the following figure, were installed late in 2002.

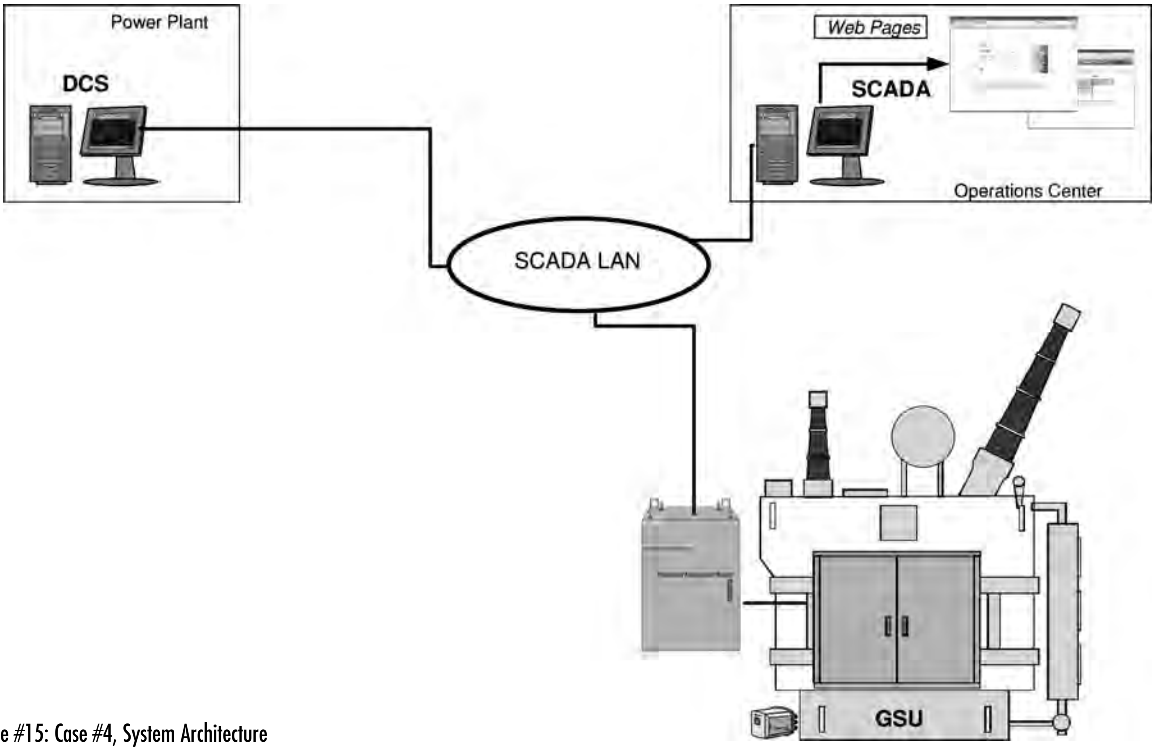


Figure #15: Case #4, System Architecture

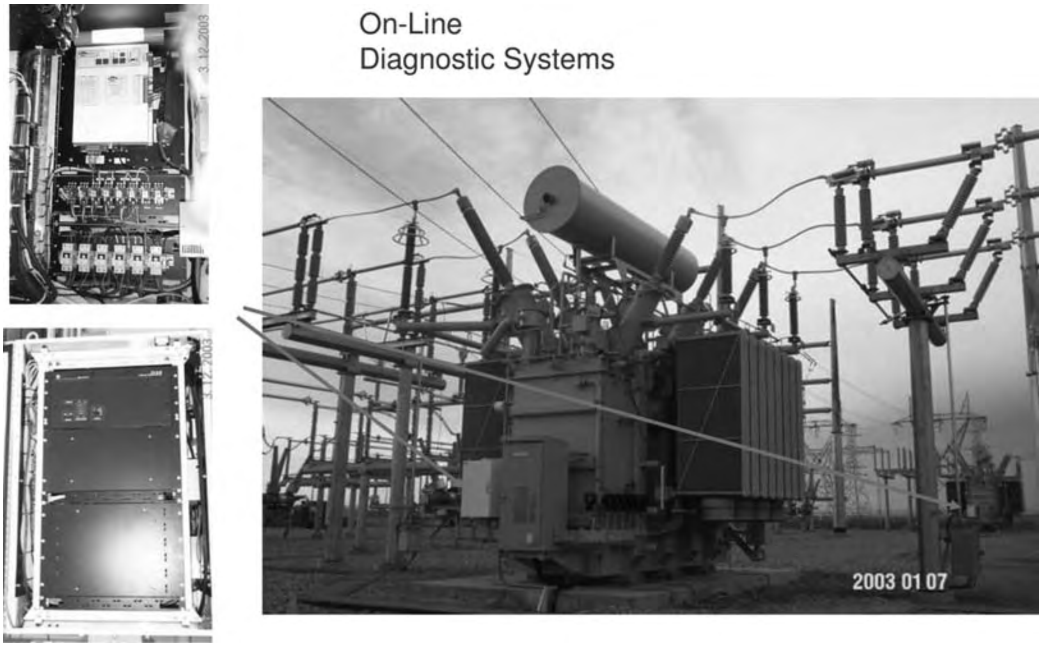


Figure #16: Case #5, Transformer Photos

System Description

This system includes the diagnostics capabilities similar to the previous example but also integrated bushing monitoring. The following listing contains the values being monitored in this case study.

Functions:

- Monitor all critical parameters
- Top Oil Temp
- Ambient Temp
- Bottom Oil Temp
- Dissolved gas in oil
- Moisture in oil
- Load current
- Voltage
- OLTC position
- OLTC remote control
- HV & LV Bushings

The Bushing monitor sensors are installed on the high- and low-voltage bushing on each phase. This allows the system to monitor the leakage current on each bushing and detect potential problems.

This system communicates directly with the SCADA system via DNP 3.0.

CASE STUDY #6

This system highlights a few additional communications and functional capabilities.

First, this system provides the diagnostic and monitoring of previous systems, including bushing monitoring.

The communication system between the transformers and the control building consists of a DNP IP communications over the local power line carrier system. It utilizes a secure PLC (Power Line Carrier) system that low-voltage wiring into an intelligent highspeed broadband networking platform. This system is useful when there is no economical method of adding communications between the transformer and the control building. This system also includes a smart gateway which has a DNP connection to a DCS and Https web based server access by authorized users.

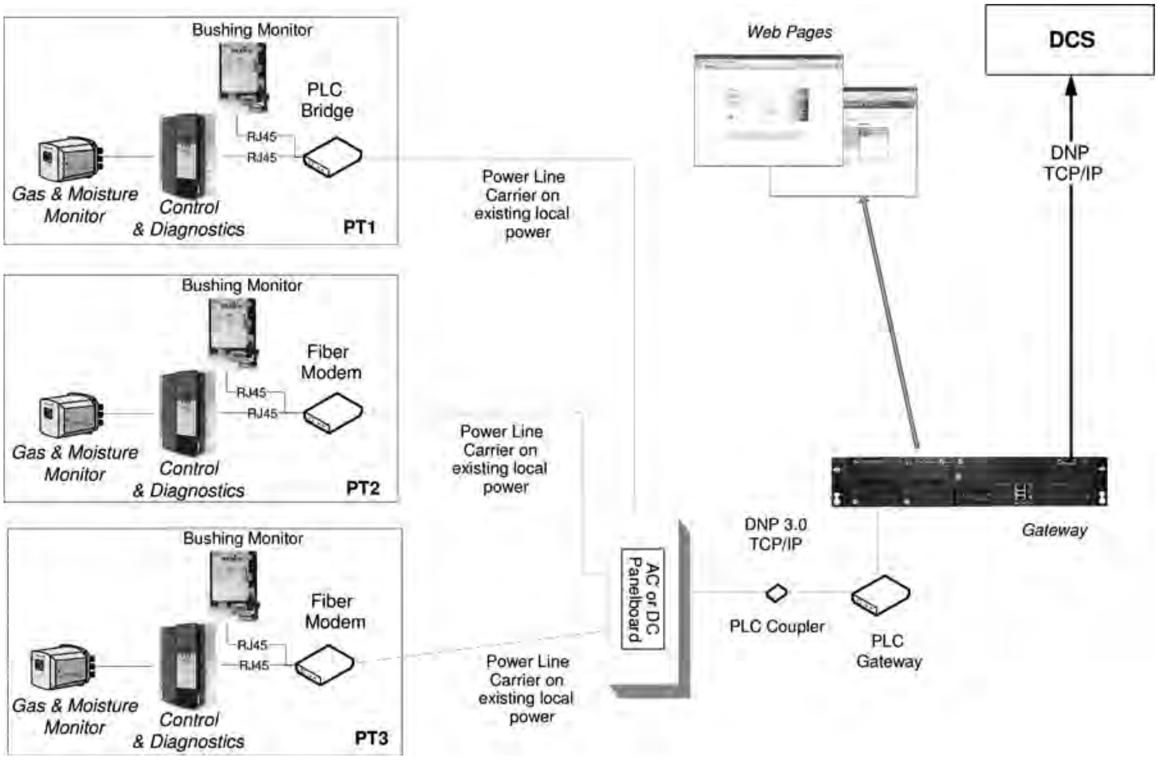


Figure #17: Case #6, System Architecture

CASE STUDY #7

The following system consists of a LTC monitoring system which communicates via dial-up modems. This system provides monitoring on the transformer and the LTC's condition including monitoring the LTC tap operations, tap operation counts, LTC tap wear factors, the temperature difference between the transformer tank and the LTC compartment, the operational characteristics while operating through the various tap positions (LTC Controls), and monitoring the drive motor current and motor index. The utility using this system now performs condition-based maintenance on their LTCs.

They also have credited this system with averting over 30 failures.

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[1] Understanding Transformer Models – Sept 04, Tony Fedele, Product Manager, GE Energy

[2] Integrated Substation Monitoring and Diagnostic (iSM&D), Overview; Document Number: 994-0039, Version: 3.00, Revision: 6, GE Energy, 18-Jun-2003,

IV. Appendices

Field validation of winding hot-spot temperature model:

- J. Aubin, P. Gervais, A. Glodjo, "Field Experience with the Application of Dynamic Models for On-line Transformer Monitoring" EPRI Substation Diagnostic Conference VI, New Orleans, February 2001.

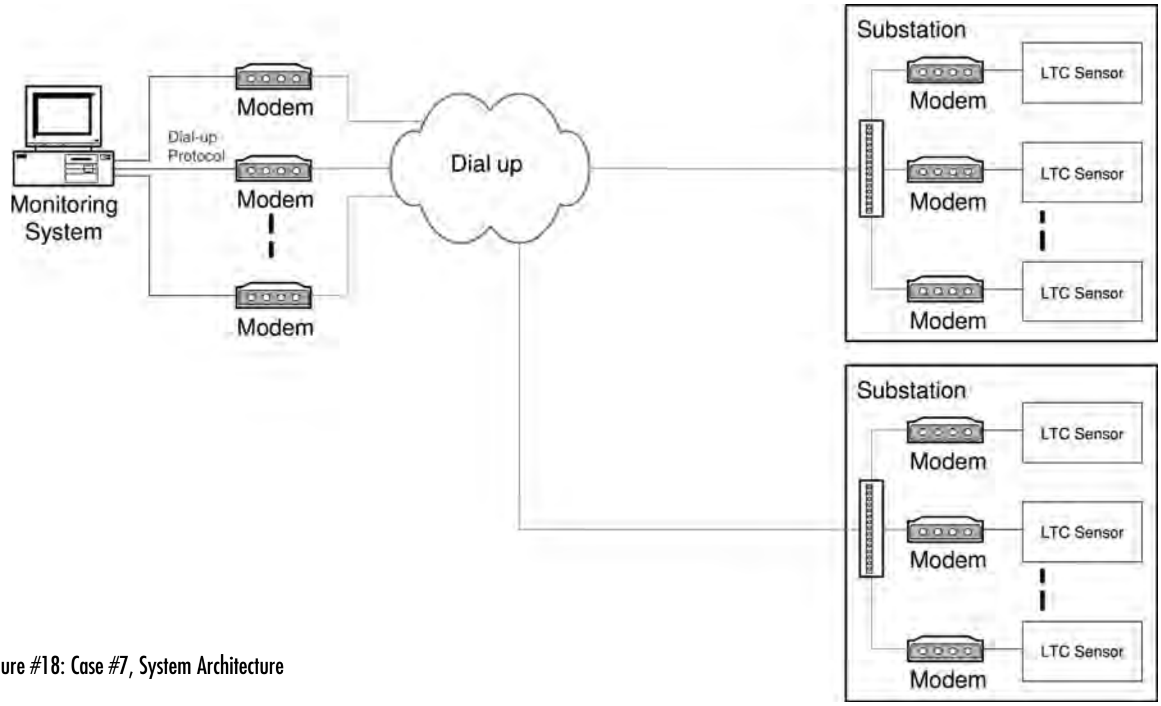

Figure #18: Case #7, System Architecture

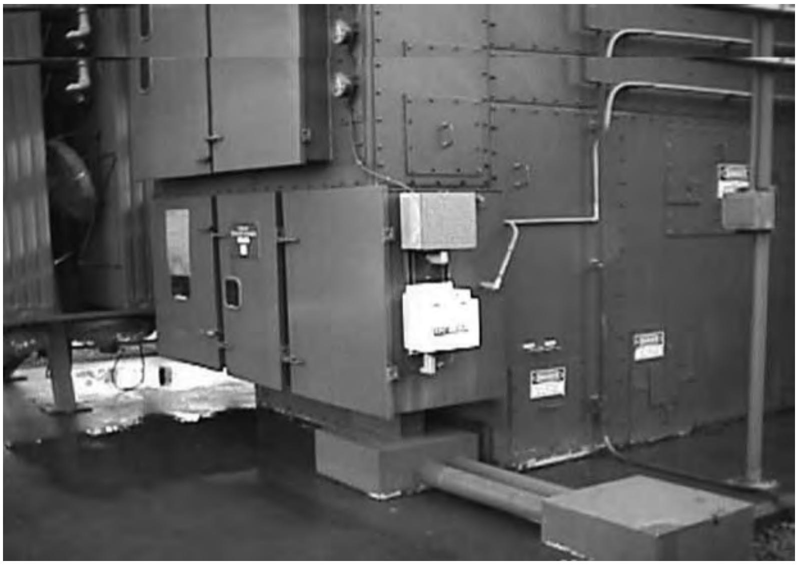

Figure #19: Case #7, LTC Sensor Installation

Field validation of moisture and bubbling model:

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- D. Pomi, Pacific Gas& Electric Co. "Discoveries of LTC Problems Which Support The Success of New Technology Monitoring and Test Devices"
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"Open LAN Solutions for Substation Automation at Ontario Hydro Services Company", J.S.K. Kwan, P.Eng, Ontario Hydro Services Company; R. Farquharson, GE Harris Energy Control Systems. Presented at Western Power Delivery Automation Conference, April 2000.

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COMPARISON OF INTERNALLY PARALLEL SECONDARY AND INTERNALLY SERIES SECONDARY TRANSGUN TRANSFORMERS

Kurt A Hofman, Stanley F. Rutkowski III, Mark B. Siehling and Kendal L. Ymker, RoMan Manufacturing Inc.

INTRODUCTION

Transgun style transformers have been in large-scale use for the past 10 years.

The concept of the transgun transformer is for the transformer to be integrally mounted to a welding gun, forming the transgun assembly. In many applications, the transgun assembly is manipulated with a robot.

The application of robotic transguns has created some challenging design requirements for the transformer. These requirements include, but are not limited to the following: light weight, compact size, secondary voltage that is capable of driving automotive weld currents through weld guns that vary in size, shape, and configuration, a thermal or KVA rating of the transformer that allows maximum production rate (spots per minute) at the selected weld current; minimize primary demand current on the power system.

A review of the above design criteria indicates that as one criteria is optimized, it may have a negative effect on another criteria. This contradiction of design requirements raises the question, “Should we design a transformer that compromises many criteria and attempts to meet all applications or should the application drive a style of transformer that best meets the specific process requirements?”

The intent of this paper is to provide technical data on the two different styles of transformers, internally parallel secondaries or internally series secondaries. The parallel or series configuration of the transformer secondary affects different application parameters.

BACKGROUND

The transformers that were used in this research have the following characteristics:

Primary	460 Volt	60 Hz.	1 (phase) AC
KVA	R Parallel	42 KVA @ 50% Duty Cycle	
	R Series	45 KVA @ 50% Duty Cycle	
	H	70 KVA @ 50% Duty Cycle	

Insulation Class: 155 °C (Class F)

Secondary Voltages:

R parallel (Rp)	6.05
R series (Rs)	10.70
H parallel (Hp)	5.22
H series (Hs)	10.44

For this research two different styles of transformers were used to compare the parallel and series configurations. In the R transformer, an internal series of secondary construction was used and the physical dimensions of the transformer were held the same as the parallel secondary R. The internal series bar occupies space which would otherwise be occupied by magnetic core material, thus reducing the amount of core in the series transformer. A reduction in magnetic core reduces the allowed secondary voltage.

The effects of this decision show in the physical size vs. secondary voltage. It is expected that the series secondary would result in doubling the secondary voltage, whereas, in the R, the secondary voltage went from 6.05 (parallel) to 10.70 (series) or an increase of 77%, a direct result of the reduced magnetic core.

The second approach to comparing the parallel secondary to the series secondary was done with the H transformer. With the H transformer, the secondary assembly was lengthened to allow room for the series bar which maintained the same magnetic core area for both transformers, resulting in a secondary voltage that doubled from parallel to series. The parallel transformer has a secondary voltage of 5.22 and the series has a secondary voltage of 10.44. The additional secondary length in the series transformer changes the physical dimensions comparing a parallel transformer to a series transformer

The two approaches to the series and parallel configuration were driven by current practice.

IMPEDANCE MATCHING

Impedance matching is the determination of transformer impedance combined with weld gun impedance to produce a total impedance of the transgun assembly. Chart 1 shows the impedance in rectangular coordinates of the four test transformers. For this investigation, three weld gun sizes are used denoted as “S” small, “M” medium, and “L” large. Chart 2 shows the measured gun impedance and physical size.

Total impedance of the transgun assembly and the transformer secondary voltages are shown in Chart 3.

The application of Ohm’s law for AC circuits (V = I x Z) weld current, I, can be solved by taking the secondary voltage and dividing it by the total impedance. The maximum tip to tip (no work) current of the transgun assemblies using the H transformer is shown in Chart 4 and graphically displayed in Figure 1.

Transformer	Resistance R (μΩ)	Reactance Xl (μΩ)	Impedance Z (μΩ)
H- Parallel	30	24	38.42
H-Series	120	96	153.67
R-Parallel	58	34	67.23
R-Series	213	65	222.70

Chart 1. Transformer Impedance Values

Gun	Resistance R (μΩ)	Reactance Xl (μΩ)	Impedance Z (μΩ)	Size (In.)
S	60	75	96.05	5.0 x 7.0
M	110	150	186.01	9.2 x 11.4
L	160	300	340.00	16.1 x 41.0

Chart 2. Gun Impedance Values

TX-Gun	Z (μΩ)	Vsec
HP-L	375.60	5.22
HP-M	223.33	5.22
HP-S	133.79	5.22
HS-L	484.99	10.44
HS-M	336.77	10.44
HS-S	248.28	10.44
RP-L	398.85	6.00
RP-M	249.16	6.00
RP-S	160.64	6.00
RS-L	521.88	10.70
RS-M	388.01	10.70
RS-S	306.80	10.70

Chart 3. Total Impedance and Secondary Voltage

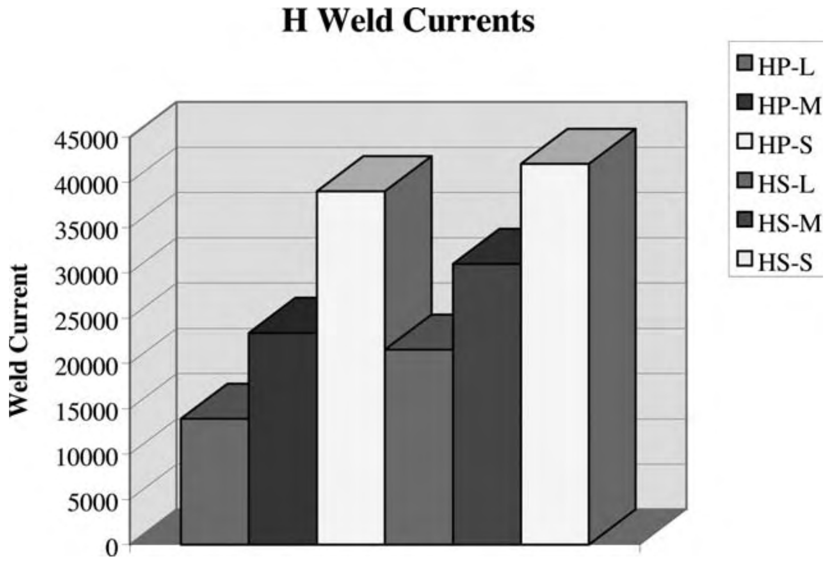


Figure 1. Weld Currents for H Transformer with Gun

Gun	HP-L	HP-M	HP-S	HS-L	HS-M	HS-S
Iweld	13898	23374	39015	21526	31000	42050

Chart 4. Weld Currents for H Transformer with Gun

Chart 5 and Figure 2 show the maximum tip to tip current of the R transformer.

Gun	RP-L	RP-M	RP-S	RS-L	RS-M	RS-S
Iweld	15043	24081	37351	20503	27576	34876

Chart 5. Weld Currents for R Transformer with Gun

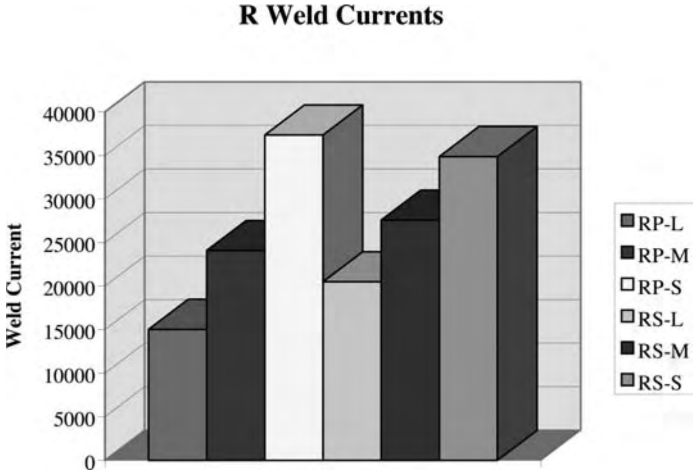


Figure 2. Weld Currents for R Transformer with Gun

A series secondary transformer has approximately four times the impedance as a parallel secondary transformer. Thus, as the weld gun impedance becomes less, the transformer impedance becomes a greater percentage of the total transgun assembly.

With a low impedance gun, demonstrated by the small gun in this investigation, a condition can arise in which a transgun assembly using a parallel transformer can produce more weld current than a transgun assembly using a series transformer. This is the effect of impedance matching. Chart 5 demonstrates the condition of impedance matching.

PRODUCTION RATE

The production rate in this investigation is defined as the number of weld cycles per minute the transformer can produce at a given weld current. For clarity, the data is presented in two different forms. In Figures 3 and 4, the data is shown in maximum allowable weld cycles per minute over a range of weld currents.

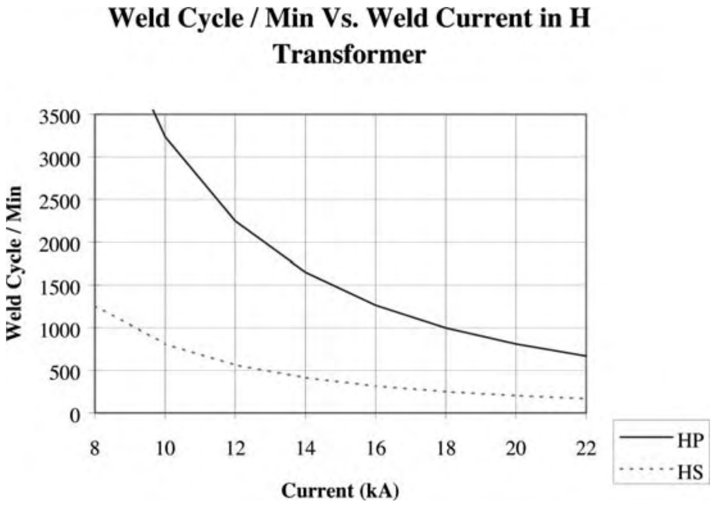


Figure 3. Weld Cycles Per Minute in H Transformer

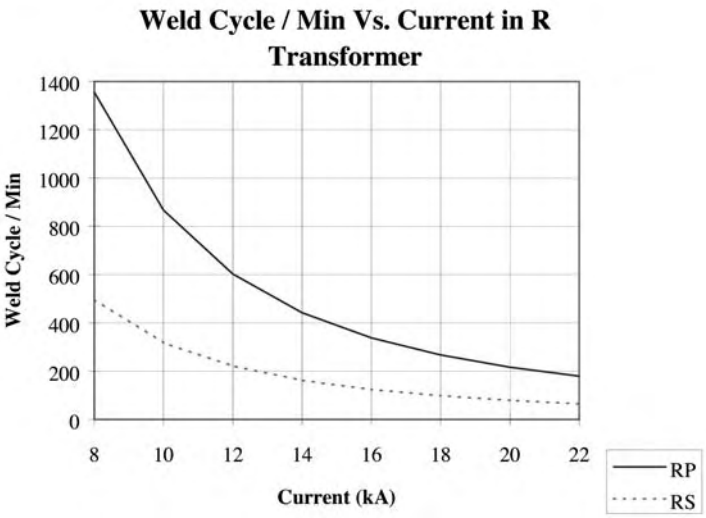


Figure 4. Weld Cycles Per Minute in R Transformer

The other method of data presentation is to assign typical weld times used in industry and determine the welds per minute. Figures 5 through 8 show the maximum welds per minute at 14 and 20 cycles of weld time over a range of weld current.

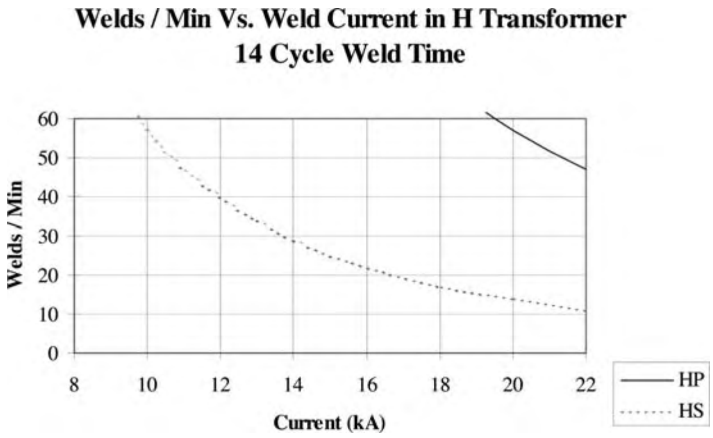


Figure 5. Welds per Minute with 14 Cycle Weld Time in H Transformer

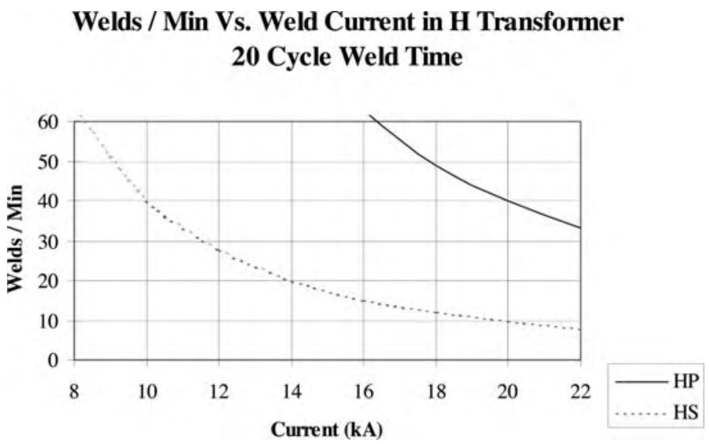


Figure 6. Welds per Minute with 20 Cycle Weld Time in H Transformer

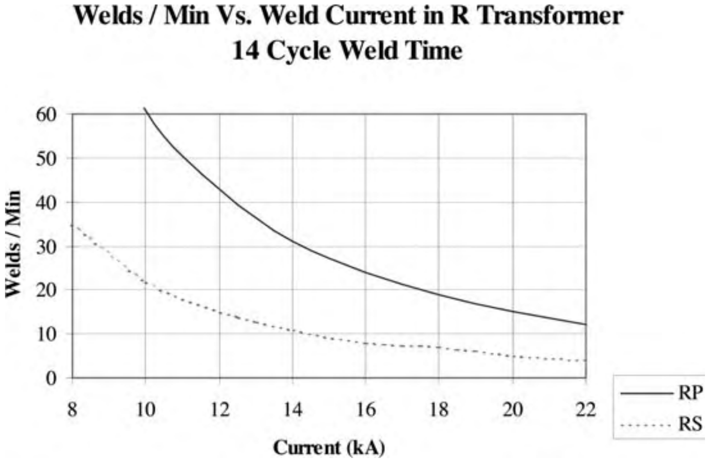


Figure 7. Welds per Minute with 14 Cycle Weld Time in R Transformer

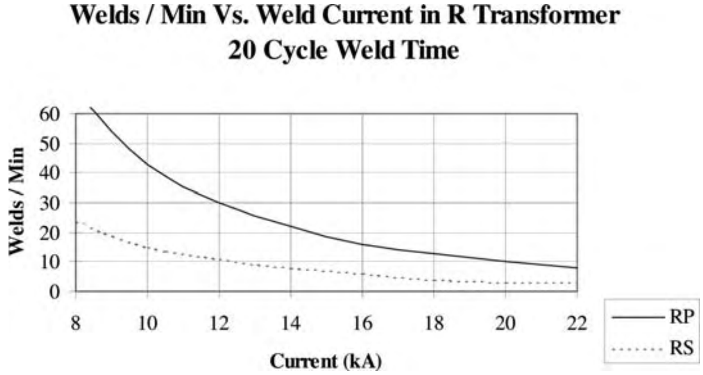


Figure 8. Welds per Minute with 20 Cycle Weld Time in R Transformer

When reviewing the data shown in figures 3 through 8, the observation can be made that the series transformer will have a lower production rate than the parallel transformer.

PRIMARY DEMAND CURRENTS

The primary current is related to the secondary current by the turns ratio of the transformer. The Appendix shows the turns ratios of the test transformers. In the H transformer, the series transformer turns ratio is one half as compared to the parallel transformer and twice the primary current for a given secondary current. Charts 6 and 7 show how the primary current relates to the secondary current for the H and R transformers. Note that the primary current, Ipri, for the R series transformer is not double that of the R parallel, as it is in the H transformer, due to the reduction of magnetic core.

Transformer	HP	HS
Iweld (A)	12,000	12,000
Ipri (A)	136	273

Chart 6. Primary Current in H Transformer

Transformer	RP	RS
Iweld (A)	12,000	12,000
Ipri (A)	158	279

Chart 7. Primary Current in R Transformer

SIZE AND WEIGHT

The size and weight of the transformer is an important variable when considering the type of transformer, parallel or series. The size and weight was held constant for the R transformer. Chart 5 and Figure 2 show that the series transformer will produce more current than the parallel transformer with the exception of a low impedance gun such as Gun S.

This report has compared equal size and weight transformers. Appendix B contains a chart showing the differences in series and parallel transformers holding the weld current constant.

CONCLUSION

The choice of transformer type utilized in a transgun assembly is determined by which criteria the user is optimizing or constrained by. These criteria include: impedance matching, size and weight, primary demand, and production rate.

In most cases, the series transformer will maximize weld current except when a low impedance gun is used. The series transformer has an advantage of reduced size and weight for a given weld current. The parallel transformer will minimize primary demand.

The parallel transformer provides an advantage of higher production rates due to the lower KVA demand. Chart 8 summarizes the advantages of each transformer type.

Conclusion Chart

Series	Parallel
• Size and Weight	• Primary Demand
• Max. Weld Current	• Small Gun Impedance
	• Production Rate

Chart 8. Advantages of Each Transformer Type

APPENDIX A

TURNS RATIOS AND TRANSFORMER DRAWINGS

Chart #9 below is the list of the turns ratios for the H transformers studied in this report.

Transformer	HP	HS
Turns Ratio	88:1	44:1

Chart 9. Turns Ratios for the H Transformer

Chart #10 below is the list of the turns ratios for the R transformers studied in this report.

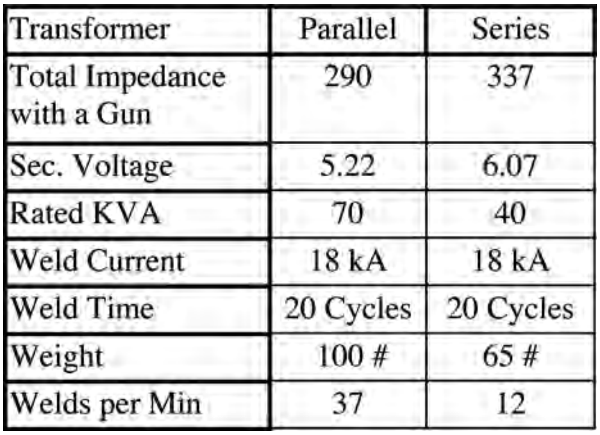
Transformer	RP	RS
Turns Ratio	76:1	43:1

Chart 10. Turns Ratios for the R Transformer

Please note that the R series and the R parallel have the same physical dimensions were as the H series and H parallel dimensions differ.

APPENDIX B

COMPARISON OF SERIES AND PARALLEL TRANSFORMERS HOLDING WELD CURRENT CONSTANT



Transformer	Parallel	Series
Total Impedance with a Gun	290	337
Sec. Voltage	5.22	6.07
Rated KVA	70	40
Weld Current	18 kA	18 kA
Weld Time	20 Cycles	20 Cycles
Weight	100 #	65 #
Welds per Min	37	12

Chart 11. Comparison Holding Weld Current Constant.

RURAL TRANSFORMER FAILURE

Fluke

PROBLEM DESCRIPTION

This case history involves the investigation of a utility transformer failure that occurred in a rural area surrounded mostly by farmland and open space. The failure occurred in a location where power quality problems are rare.

Fig. 1 shows a one-line diagram of the system. The failed transformer was at the end of a medium voltage utility feeder. The transformer secondary was configured as a 120/208V, 3-phase, 4-wire system. The load consisted of three end-users: a small apartment complex, a dairy farm and a golf course clubhouse.

The engineer began his investigation by checking for reports of problems with other transformers connected to the same feeder. This bit of research didn't turn anything up, so he concluded the problem was probably related to the secondary loads. His next step was to question the end-users.

The farm owner said his milk processing equipment was running when the transformer failed. He also said nothing unusual had occurred prior to the failure, and his equipment continued to work normally after the transformer was replaced.

The apartment manager recalled that things were quiet at his facility on the evening the failure occurred. His apartment dwellers were home, cooking dinner and watching TV. Nothing unusual had occurred.

The golf course superintendent said the club had sponsored a large tournament on the day the transformer failed. The club had rented several battery powered golf carts to supplement their normal fleet.

Operators plugged all of these in for recharging at the end of the tournament. About an hour after that, a fuse blew in the clubhouse's main service panel.

The superintendent replaced the fuse, and not long after that the power went out — this time, due to a failed transformer.

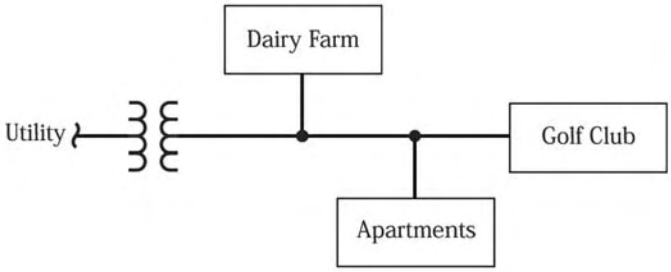


Fig. 1 Connections to the rural power transformer

MEASUREMENTS

The engineer asked to have a golf cart set up for charging, so he could record the harmonic spectrum and waveform of the battery charger current. The results are shown in Fig. 2 and Fig. 3.

THEORY AND ANALYSIS

Battery chargers are invariably non-linear loads that generate harmonic currents, due to the action of diodes or other semiconductors that convert AC to DC. The waveform shown in Fig. 2 is typical of a transformer coupled diode rectifier. The Fluke 43B showed the total harmonic distortion (THD) of the golf cart charger current to be 37%. Values above 20% would be dangerously high, given the estimated size of the charger load in relation to the total transformer load.

When harmonic currents are flowing in a transformer, the result is extra heat in the windings and core laminations.

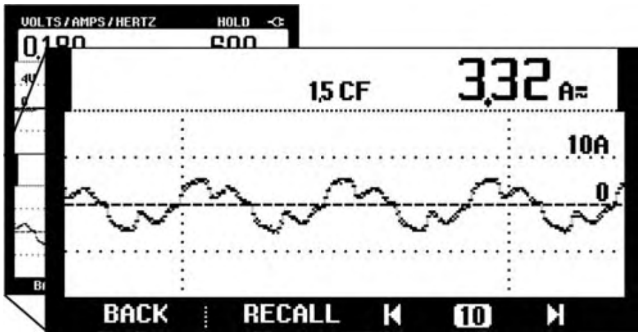


Fig. 2 Golf cart battery charger current waveform

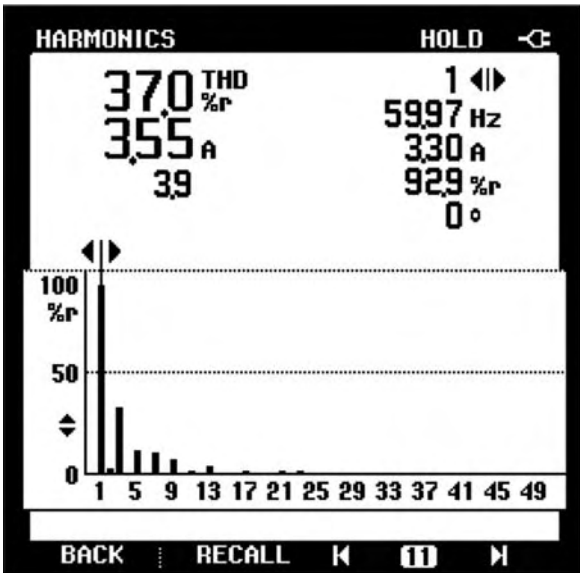


Fig. 3 Harmonic spectrum of battery charger current

LOSSES FROM HIGH-FREQUENCY EDDY CURRENTS CONSTITUTE THE PRIMARY CAUSE OF THIS EXTRA HEAT.

Some additional harmonic heating is due to skin effect, where the effective cross-section of a conductor is reduced at high harmonic frequencies. The amount of harmonic heating a transformer can tolerate is inversely proportional to the total secondary load. A heavily loaded transformer can overheat and fail if a large portion of the load current contains harmonics.

In the case of the rural transformer, three end-users contributed to the total load and all three experienced peak loads at the same time. The timing of the blown fuse and the ultimate failure indicated that the sudden addition of the large battery charger load caused the transformer to overheat.

Normally, the golf cart charger loads were staggered throughout the day. People plugged in the chargers at the conclusion of each round of golf. The tournament situation was unusual, because it replaced this staggered load pattern with a simultaneous load pattern. Operators plugged in all the charger units in the normal fleet plus those from the rental units, at about the same time. The sudden battery charger load coincided with the peak load from the apartment complex. Residential peak loads occur around dinnertime when people are using electric ranges, refrigerators, dishwashers, and TV sets.

SOLUTION

To prevent failures, the golf club supervisor agreed to use careful load management. He would restrict the total number of chargers connected at any one time, and avoid the use of chargers between 5 and 7 p.m.

PROTECTING POWER TRANSFORMERS FROM COMMON ADVERSE CONDITIONS

Ali Kazemi, Schweitzer Engineering Laboratories, Inc., Casper Labuschagne, Schweitzer Engineering Laboratories, Inc.

Abstract — Power transformers of various sizes and configurations are applied throughout the power system. These transformers play an important role in power delivery and in the integrity of the power system network as a whole.

Power transformers have operating limits beyond which transformer loss of life can occur. This paper examines the adverse conditions to which a power transformer might be subjected.

Our discussion includes transformer overload, through-fault, and overexcitation protection. We discuss each operating condition and its effect on the power transformer, and provide a solution in the protection scheme for each operating condition.

I. INTRODUCTION

In general, the main concern with transformer protection is protecting the transformer against internal faults and ensuring security of the protection scheme for external faults. System conditions that indirectly affect transformers often receive less emphasis when transformer protection is specified.

Overloading power transformers beyond the nameplate rating can cause a rise in temperature of both transformer oil and windings. If the winding temperature rise exceeds the transformer limits, the insulation will deteriorate and may fail prematurely.

Prolonged thermal heating weakens the insulation over time, resulting in accelerated transformer loss-of-life.

Power system faults external to the transformer zone can cause high levels of current flowing through the transformer.

Through-fault currents create forces within the transformer that can eventually weaken the winding integrity.

A comprehensive transformer protection scheme needs to include protection against transformer overload, through-fault, and overexcitation, as well as protection for internal faults.

This article focuses on liquid-immersed transformers because the majority of medium- and high-voltage transformers are of this type.

II. POWER TRANSFORMER CAPABILITY LIMITS

A power transformer consists of a set of windings around a magnetic core. The windings are insulated from each other and the core. Operational stresses can cause failure of the transformer winding, insulation, and core.

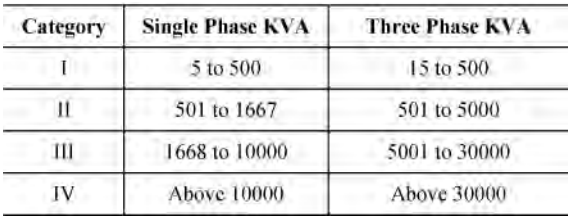
The power transformer windings and magnetic core are subject to a number of different forces during operation [3]:

- Expansion and contraction caused by thermal cycling.
- Vibration caused by flux in the core changing direction every half cycle.
- Localized heating caused by eddy currents in parts of the winding, induced by magnetic flux.
- Impact forces caused by through-fault currents.
- Thermal heating caused by overloading.

ANSI/IEEE standards [1] [2] provide operating limits for power transformers. Initially, these operating limits only considered the thermal effects of transformer overload. Later, the capability limit was changed to include the mechanical effect of higher fault currents through the transformer. Power transformer through-faults produce physical forces that cause insulation compression, insulation wear, and friction-induced displacement in the winding. These effects are cumulative and should be considered over the life of the transformer.

Table I shows four categories [1] for liquid-immersed power transformers, based on the transformer nameplate rating.

Table 1: Transformer Categories



Category	Single Phase KVA	Three Phase KVA
I	5 to 500	15 to 500
II	501 to 1667	501 to 5000
III	1668 to 10000	5001 to 30000
IV	Above 10000	Above 30000

To provide a more comprehensive representation of the long-term effects of system conditions on power transformers, each category includes through-fault capability limits which are a function of the maximum current through the transformer.

The maximum current (in per unit [p.u.] of the transformer base rating) is calculated based on the transformer short-circuit impedance for category I and II transformers.

Maximum current calculation for category III and IV transformers is based on the overall impedance of the transformer short-circuit impedance and the system impedance.

A. CATEGORY I TRANSFORMERS

Fig. 1 shows the through-fault capability limit curve for category I transformers. The curve reflects both thermal and mechanical considerations. For short-circuit currents at 25–40 times the base current, the I2t limit of 1250 defines the curve, where I is the symmetrical fault current in multiples of the transformer base current and t is in seconds.

Current (I) is based on the transformer's per-unit short circuit impedance. A transformer with 4 percent impedance will have a maximum short circuit current of 25 p.u. (1/0.04), which results in a time of 2 seconds (1250/252) for its throughfault capability limit.

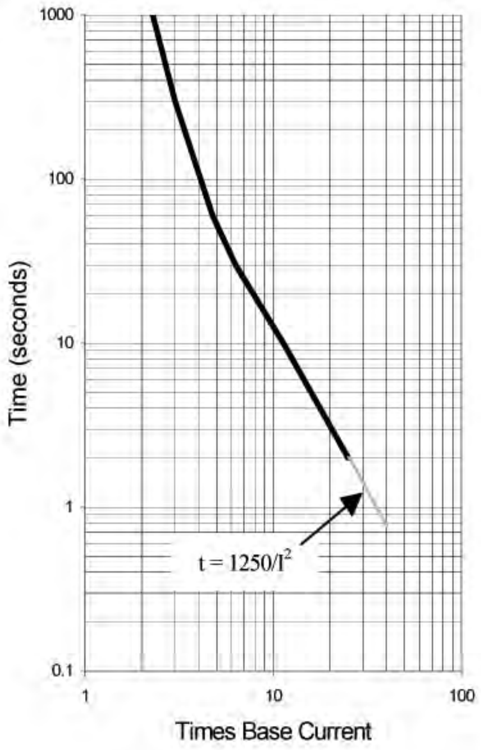


Fig. 1. Through-Fault Capability limit curve for Liquid-Immersed Category

I TRANSFORMERS

B. CATEGORY II AND III TRANSFORMERS

For Category II and III transformers, the IEEE standard provides an additional through-fault capability limit curve.

The additional curve takes into account the fault frequency that the transformer is subjected to throughout its entire life. In general, use a frequent-fault curve if fault frequency is higher than ten through-faults for category II transformers and higher than five through-faults for category III transformers. Fault frequency is considered over the life of the transformer.

Fig. 2 represents the through-fault capability limit curve for category II and III transformers that experience infrequent faults. The curve is limited to two seconds.

To acknowledge the cumulative nature of damage caused by through-faults, the standard supplements the through-fault capability limit curve to reflect mechanical damage. It calculates the I2t curve based on the actual transformer impedance.

For category II transformers, consider the mechanical duty for fault currents higher than 70 percent of maximum possible short-circuit current. For category III and IV transformers, consider mechanical duty for through-fault currents higher than 50 percent of maximum possible short-circuit current.

Fig. 3 shows the through-fault capability limit curve for a category II transformer with 7 percent impedance. The I2t calculation is at maximum short-circuit current for a time of 2 seconds.

For a transformer with 7 percent impedance, I2t calculates at 408 as shown below:

I = 1/0.07 = 14.29; this is the maximum short-circuit current in p.u. of transformer base rating I2t = (14.29)2 • .2 = 408

The lower portion of the curve is 70 percent of maximum short-circuit current and the I2t calculated above.

I = 0.7 • 14.29 = 10
t = 408/(I)2 = 4.08

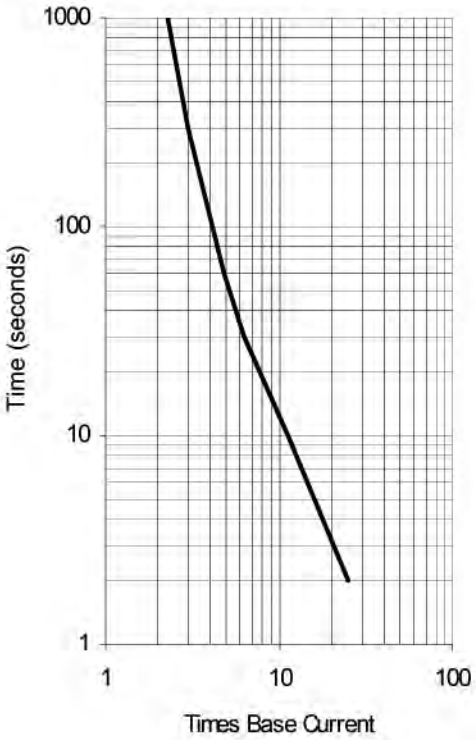


Fig. 2. Through-Fault Capability Limit Curve for Liquid-Immersed Category II and III Transformers with Infrequent Faults

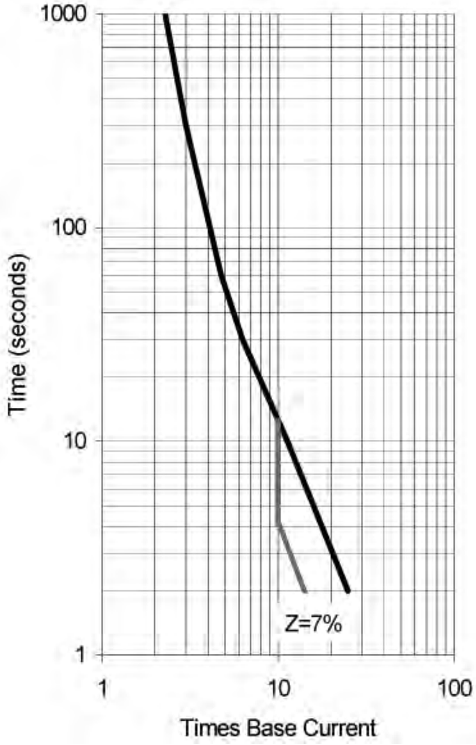


Fig. 3. Through-Fault Capability Limit Curve for Liquid-Immersed Category II Transformers with Frequent Faults

C. CATEGORY IV TRANSFORMERS

Fig. 4 shows the through-fault capability limit curve for category IV transformers. The curve represents both the frequent and the infrequent fault occurrences. For category III and IV transformers, the mechanical duty limit curve starts at 50 percent of the short circuit current.

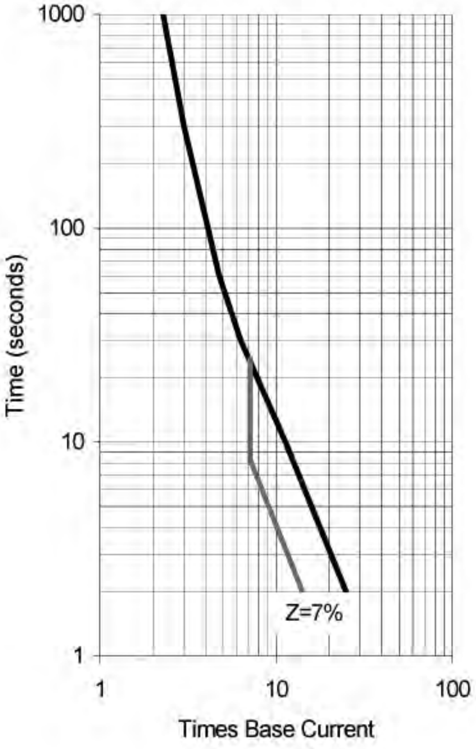


Fig. 4. Through-Fault Capability Limit Curve for Liquid-Immersed Category IV Transformers

D. PROTECTION CONSIDERATIONS

After determining the proper through-fault capability limit curve for a particular transformer, select a time-overcurrent characteristic to coordinate with the through-fault capability limit curve.

In distribution transformer applications where a number of feeders are connected to the low-voltage bus, the feeder relays become the first line of defense. IEEE Standard C37.91 recommends [3] setting the inverse time-overcurrent characteristic of the feeder relays to coordinate with the through-fault capability limit curve of the transformer, as shown in Fig. 5.

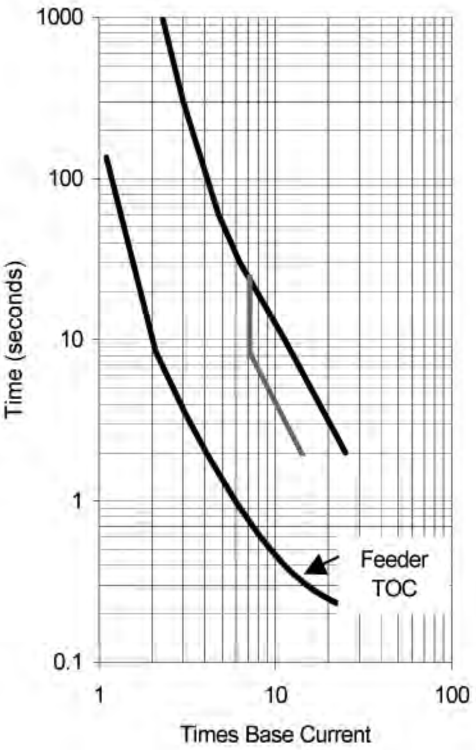


Fig. 5. TOC Coordination with Category IV Transformer Through-Fault Capability Limit Curve

Coordinating an overcurrent element with an I2t thermal element requires further consideration. Although the extremely inverse time-overcurrent characteristic of the overcurrent relay seems to emulate the shape of the thermal curve, the coordination is only valid for a fixed initial overcurrent condition [4]. Once an overload or through-fault condition causes the transformer winding temperature to rise, coordination between the overcurrent relay and the thermal element is no longer valid. In this situation, the overcurrent relay does not prevent thermal damage caused by cyclic overloads.

III. TRANSFORMER OVERLOAD

A. OVERCURRENT VS. OVERLOAD

For this paper, we define overcurrent as current flowing through the transformer resulting from faults on the power system. Fault currents that do not include ground are generally in excess of four times full-load current; fault currents that include ground can be below the full-load current depending on the system grounding method. Overcurrent conditions are typically short in duration (less than two seconds) because protection relays usually operate to isolate the faults from the power system.

Overload, by contrast, is current drawn by load, a load current in excess of the transformer nameplate rating. IEEE standard [5] lists nine risks when loading large transformers beyond nameplate ratings. In summary, loading large power transformers beyond nameplate ratings can result in reduced dielectric integrity, thermal runaway condition (extreme case) of the contacts of the tap changer, and reduced mechanical strength in insulation of conductors and the transformer structure.

Three factors, namely water, oxygen, and heat, determine the insulation (cellulose) life of a transformer. Filters and other oil preservation systems control the water and oxygen content in the insulation, but heat is essentially a function of the ambient temperature and the load current. Current increases the hottest-spot temperature (and the oil temperature), and thereby decreases the insulation life span.

Equation (1) is used as an indication of the insulation-aging effect of overloading a transformer.

$$\%LOL = \frac{H}{ILIFE} \bullet 100 \qquad (1)$$

where:
%LOL percentage loss-of-life
H = Time in hours
ILIFE = Insulation life

In general, assume the insulation life of a transformer to be 180,000 hours and the rated hottest-spot temperature to be

110ºC. Therefore, a transformer operating at the rated hottestspot temperature of 110ºC for 24 hours ages at a rate of 0.0133 percent, calculated as follows:

$$\%LOL = \frac{24 \cdot 100}{180{,}000} = 0.01333\%$$

However, overloading the transformer decreases the insulation life span exponentially. To relate the hottest-spot temperature to the per-unit insulation life, we calculate FAA, the Aging Acceleration Factor. Equation (2) shows the calculation for FAA, with 15,000 being a design constant.

$$FAA = \exp^{\left[\frac{15{,}000}{383} - \frac{15{,}000}{\theta_H + 273}\right]} \qquad (2)$$

where:

θ_H is the calculated hottest-spot temperature

An FAA factor of 10 means that, at the present hottest-spot temperature, the transformer insulation ages 10 times faster than the per-unit life over a given time interval. In terms of temperature, an FAA of 10 corresponds to a hottest-spot temperature of approximately 135ºC.

B. AMBIENT TEMPERATURE

Excessive load current alone may not result in damage to the transformer if the absolute temperature of the windings and transformer oil remains within specified limits. Transformer ratings are based on a 24-hour average ambient temperature of 30°C (86°F). Note that the ambient temperature is the air in contact with the radiators or heat exchangers.

Table II shows the increase or decrease from rated kVA for other than average daily ambient temperature of 30°C.

TABLE II
TRANSFORMER LOADING WITH TEMPERATURE AS A FACTOR

Type of cooling	Percentage of kVA rating Decrease load for each °C higher than 30°C	 Increase load for each °C lower than 30°C
Self-cooled (OA)	1.5	1.0
Water-cooled (OW)	1.5	1.0
Forced-air cooled (OA/FA, OA/FA/FA)	1.0	0.75
Forced-oil, -air, -water, -cooled (FOA, FOW, and OA/FOA/FOA)	1.0	0.75

C. THERMAL MODELS INCLUDING AMBIENT TEMPERATURE

More sophisticated transformer thermal models [5] use load current as well as the ambient temperature to calculate Top-Oil temperature and hottest-spot temperature.

To calculate the absolute Top-Oil temperature and hottest-spot temperature, the model adds the calculated Top-Oil and hottest-spot temperatures to the measured ambient temperature (subtract for a temperature drop). When the ambient temperature is not available, or communication with the device that supplies the ambient temperature information is lost, the thermal model uses a fixed value as reference for the ambient temperature. However, using a fixed value instead of the actual ambient temperature as reference means that the model cannot indicate whether actual damage will occur at any particular level of overload.

D. THERMAL MODELS EXCLUDING AMBIENT TEMPERATURE

Although less accurate, models without direct ambient temperature can still provide useful information as to the temperature rise of the transformer oil when constant current flows.

These models project the temperature rise within the transformer as a function of (constant) load current flowing though the transformer. For example, looking at the manufacturer's literature, we see that a hypothetical transformer has a time constant (TC) of one hour. Using Equation (3), we calculate that the transformer will reach steady-state temperature after five hours (five time constants) when constant full-load current flows.

$$\theta(t) = I_{FL}\left(1 - e^{\frac{-t}{TC}}\right) \qquad (3)$$

where:

θ = Transformer oil temperature
I_{FL} = Transformer full-load current
TC = Time constant
t = Time in seconds

Furthermore, we can calculate that, if full-load current flows for one hour, the temperature is approximately 63 percent of the final value (solid curve in Fig. 6). However, we see that if we overload the transformer by 20 percent, the temperature is approximately 75 percent of the final value after one hour (dashed curve in Fig. 6).

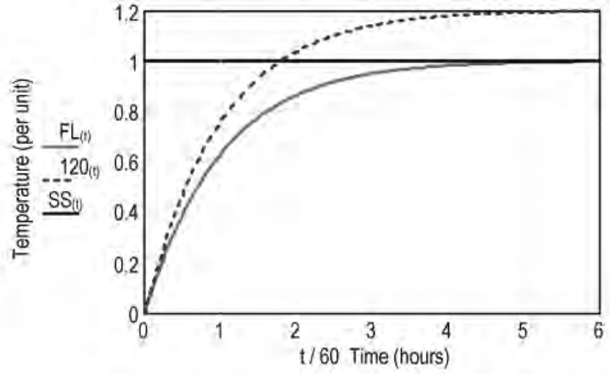


Fig. 6. Oil Temperature Curves For Full-Load Current and Twenty Percent Overload Current

We now use this information (75 percent) as a warning signal that we are overloading the transformer. Because we do not measure the ambient temperature, we cannot determine whether actual damage will occur at this level of overload.

E. COOLING SYSTEM EFFICIENCY

Many installations provide remote thermal devices (RTDs) for both ambient temperature and oil temperature measurement.

Measuring both ambient temperature and oil temperature provides a method for comparing calculated oil-temperature values to measured oil-temperature values. Ideally, calculated oil-temperature values and measured oil-temperature values should be the same. Differences between calculated and measured values can indicate that the cooling system is not performing at full efficiency, resulting from such problems as defective fan motors. At first installations, a practical approach is to use the difference between calculated and measured values to fine-tune setting of transformer constants.

Because transformer constants are not always available at the time of commissioning, some constants may have been assumed during the setting process. Once we establish that the cooling system is in good working order, we can assume that the difference between calculated and measured values is the result of incorrect transformer constant settings. After adjusting the transformer constants to the point where calculated and measured values are the same, we can now attribute any subsequent deviations in calculated and measured values can now be attributed to lower efficiency of the cooling system.

F. THERMAL PROTECTION APPLICATION EXAMPLE

The idea behind a thermal element is to provide the system operator with meaningful data about the state of the transformer.

The thermal element provides data for determining whether a transformer can withstand further short-term or long-term overloads without sacrificing transformer loss-of-life.

This information is a function of the ambient temperature, transformer-loading history, present loading condition, and cooling system efficiency.

The inputs to the transformer thermal monitor include transformer Top-Oil temperature, ambient temperature, and transformer loading indication provided through either the high-side or the low-side current transformers.

Fig. 7 shows a one-line diagram for a transformer protection relay providing differential protection and thermal monitoring for the transformer. RTDs provide Top Oil and ambient temperatures to the relay.

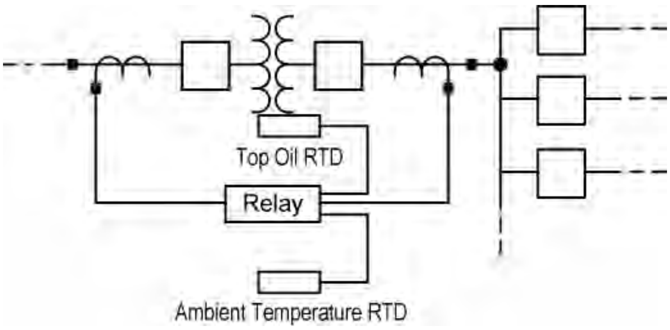
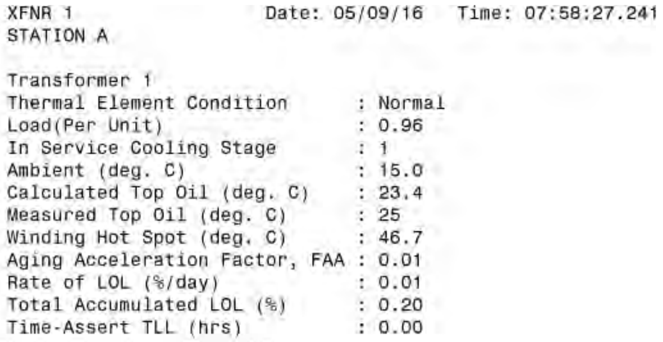


Fig. 7. Transformer Protection Relay With Connected RTDs for Thermal Monitoring

The thermal element provides the transformer thermal status both as alarm points and as a report. The alarm points indicate whether a measured value exceeds a settable threshold.

These alarm points might include Top-Oil Temperature, Hottest-spot Temperature, Aging Acceleration Factor, Daily Rate of Loss-of-Life, and Total Loss-of-Life.

The thermal element report is shown in Fig. 8.



```
XFNR 1                    Date: 05/09/16   Time: 07:58:27.241
STATION A

Transformer 1
Thermal Element Condition       : Normal
Load(Per Unit)                  : 0.96
In Service Cooling Stage        : 1
Ambient (deg. C)                : 15.0
Calculated Top Oil (deg. C)     : 23.4
Measured Top Oil (deg. C)       : 25
Winding Hot Spot (deg. C)       : 46.7
Aging Acceleration Factor, FAA  : 0.01
Rate of LOL (%/day)             : 0.01
Total Accumulated LOL (%)       : 0.20
Time-Assert TLL (hrs)           : 0.00
```

Fig. 8. Transformer Thermal Report

IV. THROUGH-FAULT MONITORING

As discussed previously, through-fault current produces both thermal and mechanical effects than can be damaging to the power transformer. The mechanical effects, such as winding compression and insulation wear, are cumulative. The extent of damage from through-faults is a function of the current magnitude, fault duration, and total number of fault occurrences.

Power transformers throughout the power system experience different levels of through-fault current in terms of magnitude, duration, and frequency. The recording capability of some transformer protection relays allows for monitoring and recording of the through-fault current. The relay records the cumulative I2t value for each phase and compares it against a threshold to provide an alarm. Fig. 9 shows the logic diagram for the cumulative through-fault logic.

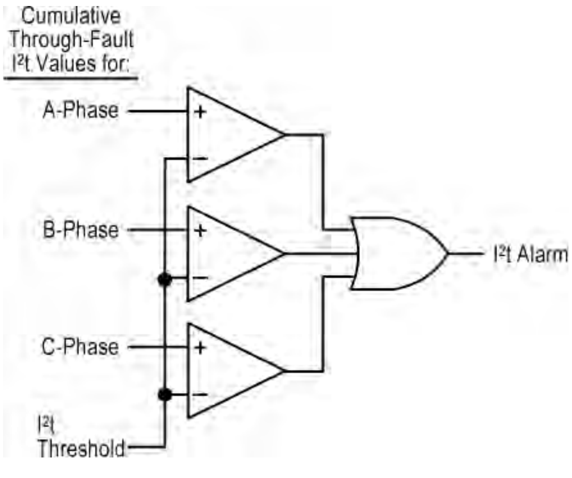


Fig. 9. Cumulative Through-Fault Logic

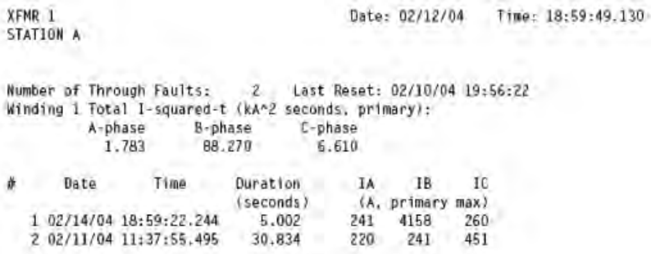
The recorded values assist the maintenance crew in prioritizing and scheduling transformer maintenance and testing.

Over time, the recorded values also provide additional information in determining problems (winding insulation failure, insulation compression, loose winding, etc.) with the power transformer.

Excessive through-fault occurrences within a given period can also indicate the need for maintenance such as tree trimming and right of way clearance [8].

Fig. 10 shows the through-fault report for a transformer.

The report provides the total I2t value for each phase. The report also provides the date, time, duration, and maximum current through the transformer for each occurrence.



```
XFMR 1                              Date: 02/12/04    Time: 18:59:49.130
STATION A


Number of Through Faults:     2    Last Reset: 02/10/04 19:56:22
Winding 1 Total I-squared-t (kA^2 seconds, primary):
          A-phase       B-phase       C-phase
            1.783        88.270         6.610

#      Date        Time        Duration       IA      IB      IC
                               (seconds)      (A, primary max)
   1 02/14/04 18:59:22.244      5.002         241    4158     260
   2 02/11/04 11:37:55.495     30.834         220     241     451
```

Fig. 10. Transformer Through-Fault Report

V. TRANSFORMER OVEREXCITATION

The flux in the transformer core is directly proportional to the applied voltage and inversely proportional to the frequency.

Overexcitation can occur when the per-unit ratio of voltage to frequency (Volts/Hz) exceeds 1.05 p.u. at full load and 1.10 p.u. at no load. An increase in transformer terminal voltage or a decrease in frequency will result in an increase in the flux.

Overexcitation results in excess flux, which causes transformer heating and increases exciting current, noise, and vibration.

Some of the possible causes of overexcitation are:

- Problems with generator excitation system
- Operator error
- Sudden loss-of-load
- Unloaded long transmission lines

A. TRANSFORMER DIFFERENTIAL RELAY AND OVEREXCITATION

Saturation of the power transformer core caused by overexcitation results in the flow of excitation current. In an extreme case, the increase in excitation current can cause the transformer differential relay to operate. Because the characteristic of the transformer differential relay does not correlate to the transformer overexcitation limit curve, it is impractical to depend on transformer differential protection to provide overexcitation protection. Furthermore, operation of the transformer differential relay for an overexcitation condition, which is a system phenomenon, can lead fault investigators to start their investigation at the transformer instead of looking for system disturbances. Use a Volts/Hz element to provide overexcitation protection. Under overexcitation conditions, block or restrain the differential element to prevent false operations.

If a Volts/Hz element is not available, use the harmonic content of the excitation current to determine the degree of overexcitation of the transformer core. Table III shows typical harmonic content of the excitation current.

The excitation current consists mainly of odd harmonics, with the third harmonic being the predominant harmonic. The third harmonic is a triplen harmonic [9]. Delta-connected transformer windings (power or current transformers) filter out triplen harmonics (3, 9, 15, etc.). Since the next highest harmonic is the fifth harmonic, most transformer differential relays use the fifth harmonic to detect overexcitation conditions.

In applications where the power transformer might be overexcited, block the differential element from operating on transformer exciting current.

TABLE III.
TRANSFORMER EXCITATION CURRENT AND HARMONICS

Frequency	Magnitude (primary amps)	% of Nominal
Fundamental	22.5	52.0
Third	11.1	26.0
Fifth	4.9	11.0
Seventh	1.8	4.0

B. OVEREXCITATION PROTECTION

Obtain the overexcitation limit for a particular transformer through the transformer manufacturer. The overexcitation limit is either a curve or a set point with a time delay. Fig. 11 shows typical overexcitation limit curves for different transformers.

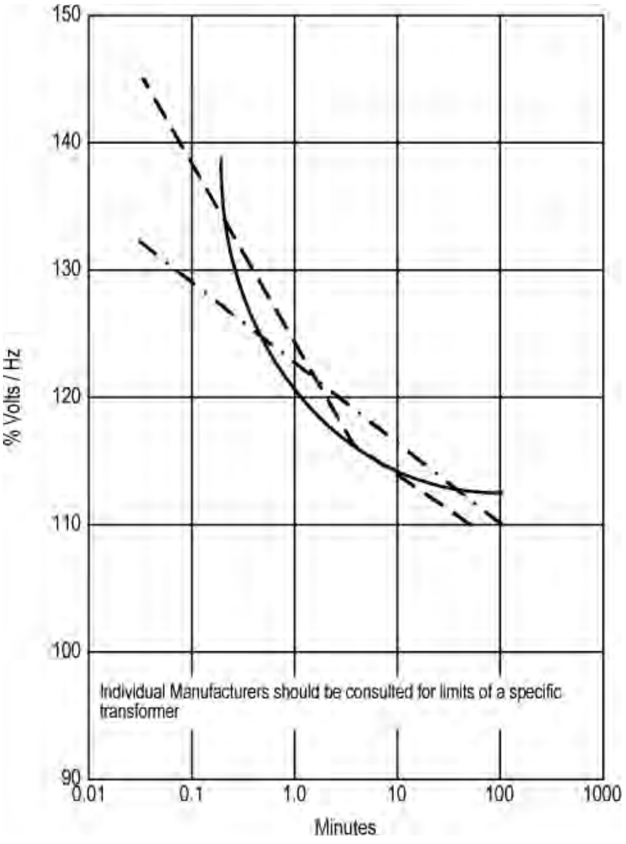


Fig. 11. Typical Transformer Overexcitation Limit Curves

Provide overexcitation protection for power transformers through a Volts/Hz element that calculates the ratio of the measured voltage to frequency in p.u. of the nominal quantities.

In applications that provide overexcitation protection for a generator step-up (GSU) transformer, consider the overexcitation limits of both the GSU and the generator. Then set the overexcitation element to coordinate with the limit curves of both the GSU and the generator. Fig. 12 shows the coordination of the overexcitation element with the generator and the GSU limit curves. Use a composite limit curve to achieve proper coordination.

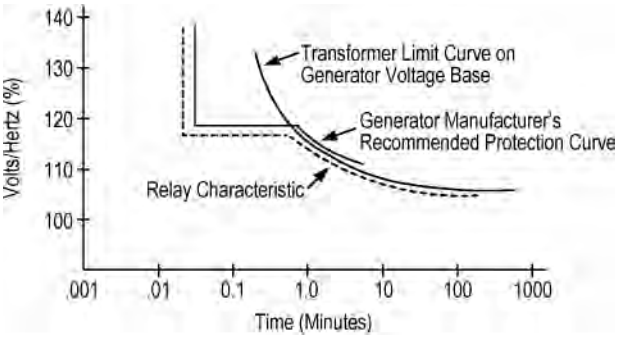


Fig. 12. Overexcitation Protection Coordination Curve

VI. CONCLUSION

Power transformers play a significant role in power system delivery. Proper application of relay elements that monitor a transformer's thermal state and through-faults can provide both short and long term benefits. These benefits include:

- Transformer overload protection, including cyclic overloads
- Continuous transformer thermal status indication that allows the system operator to make transformer loading decisions based on transformer thermal state
- Cooling system efficiency indication
- Records of cumulative per phase I2t values as seen by the transformer
- Settable I2t alarm thresholds that can notify the system operator of excessive through-fault current seen by the transformer
- Cumulative I2t values as a measure to prioritize transformer maintenance

Overexcitation is a system condition and is not limited to generating stations. Proper application of Volts/Hz elements can prevent damage to transformers resulting from system overvoltage or underfrequency conditions.

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CT SATURATION IN INDUSTRIAL APPLICATIONS - ANALYSIS AND APPLICATION GUIDELINES

Bogdan Kasztenny, Manager, Protection & Systems Engineering, GE Multilin; Jeff Mazereeuw, Global Technology Manager, GE Multilin; Kent Jones, Technology Manager, GE Multilin - Instrument Transformers Inc. (ITI)

1. INTRODUCTION

It is possible that relatively low-ratio CTs are applied for protective relaying of small loads fed from switchgear and motor controllers of relatively high short-circuit capacity. Assume the worst-case scenario of 64kA available fault current from bus feeding a small motor load of normal current below 50A. In theory, CTs rated as low as 50:5 and relay class C10 may be applied for protection purposes.

Realizing that 64kA of fault current is 1080 times the rated current of the 50:5 CT, the magnitude of the problem is evident. Protection class CTs are designed to work in the linear range, with minimal errors and minimal waveform distortion, only up to 20 times the rated nominal current with the burden as defined by the relay class (saturation voltage) of the CT per IEEE Std. C57.13.

Well-established and relatively accurate equations are available for calculation of the actual maximum primary current for saturation-free operation under any specific burden, any specific X/R ratio, and any specific residual flux in the CTs. This engineering practice is of little help here: A CT fed with a primary current hundreds of times its rated current will saturate severely - only relatively short duration peaks of limited current will be observed from the secondary of the CT. These peaks can be as low as 5-10% of the ratio current, and will last a small fraction of the half-cycle, down to 1-2ms in extreme cases. As a result, only a very small portion of the actual ratio current is presented to protective relays fed from such severely saturated CTs. In terms of the true RMS value, the secondary current may be as low as 1-2% of the expected RMS secondary current.

On the surface, it may seem that a severe problem takes place here – the fault current is so high that it virtually stops the CT from passing the signal to the relay. The relay does not see enough proportional secondary current during severe faults in order to operate its short circuit protection. The upstream relay, using CTs of a much higher ratio, measures the fault current more accurately and trips. Zone selectivity is lost because the poor low-ratio CT was "blinded" to the fault.

It is justified to assume that vast majority of industrial applications are not supported by computer simulation studies (EMTP) of saturated CTs, or any lengthy and sophisticated CT analysis. At the same time, there is a population of relays installed on high capacity buses and fed from low ratio CTs. An obvious question arises: why does the above problem not demonstrate itself in the field?

In this paper we will analyze the problem in detail and explain its underlying mechanics.

Several GE Multilin's relays are analyzed in terms of their response to heavily saturated waveforms. A formal, compact and easy-to-grasp method is shown to present complex relations between the CT response and the response of any given relay. Based on this graphical method, one can quickly evaluate the problem (do I have a problem when using relay X, with CT Y, under fault capacity Z, and overcurrent pickup setting Q?), and clearly see alternative solutions if a problem truly exists (i.e. definition of a method to match relays with CTs).

This paper illustrates that many unknowns in analysis do not have significant impact on the outcome. Reasonable conclusions will be evident from the results, even though broad assumptions are made in the model.

This exploratory analysis shows that severely saturated CTs only slightly reduce short circuit tripping capabilities of GE Multilin's relays. Given the typically applied settings, there is no danger of a failure to trip from instantaneous overcurrent functions even in extreme cases of very high short-circuit currents and low-ratio CTs.

2. SEVERE SATURATION OF LOW-RATIO CTS

Well-established engineering practice exists for CT selection to ensure saturation-free operation of protection CTs at a given short circuit level, CT burden, X/R ratio and assumed residual flux. In the context of this paper, it is assumed that this engineering technique is not applied, and severe saturation will occur for short circuits within the protected zone (motor, feeder, cable or bus).

Analytical analysis of a saturated CT is not practical. Only "time to saturation" may be approximated with relative ease, and is used in some protection applications. More detailed analytical analysis is not in the realm of practical engineering.

Computer simulations are the only efficient way to extract the required information on secondary signals. These are burdensome for everyday engineering in the industrial domain.

This article uses computer simulation to derive simple and practical analysis and engineering charts to address the problem.

Figures 1 and 2 present plots of the proportional secondary CT current, and the simulated secondary current for a 50:5, C10, CT with a 0.2ohm resistive burden under the fault current of 10 times nominal current (without and with full DC offset, respectively). This poor performance CT with this particular burden saturates slightly under 500A AC current (Figure 1), and accordingly more when full DC offset is present in the primary current (Figure 2). This document uses a digital model of a CT. More information on the model and its validation can be found in Section 7.

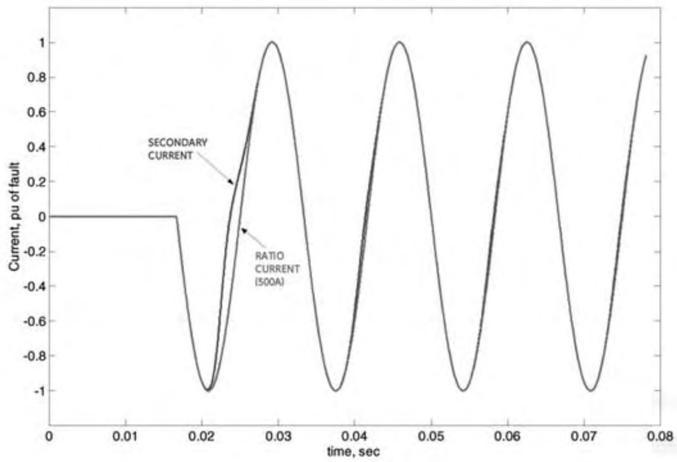

Fig.1. 50:5, C10, CT with a burden of 0.2ohms under fault current of 500A (symmetrical).

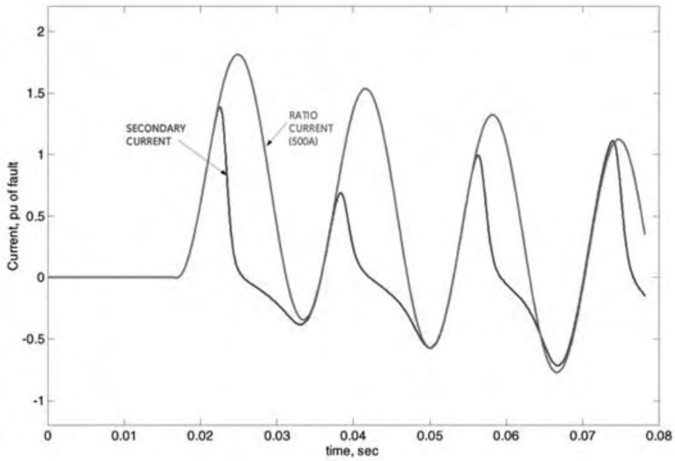

Fig.2. 50:5, C10, CT with a burden of 0.2ohms under fault current of 500A (fully offset).

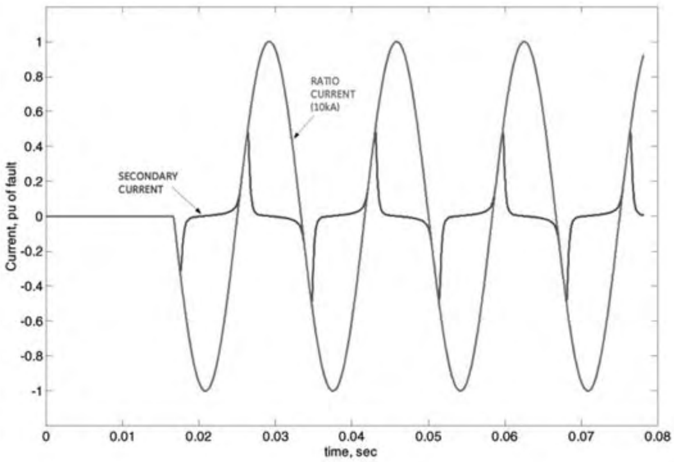

Fig.3. 50:5, C10, CT with a burden of 0.2ohms under fault current of 10kA (symmetrical).

Figures 3 and 4 present the performance of the same CT under the fault current of 200 times the nominal, i.e. 10kA. Now, the saturation is much more severe.

This article focuses on extreme cases of CT saturation, with primary current as high as 1000 times the rated value.

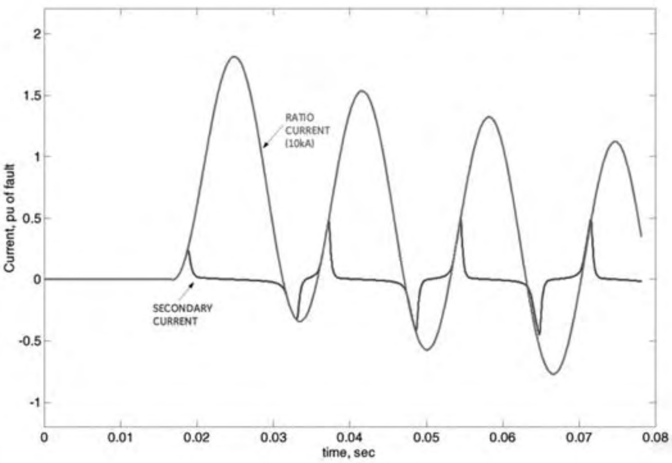

Fig.4. 50:5, C10, CT with a burden of 0.2ohms under fault current of 10kA (fully offset).

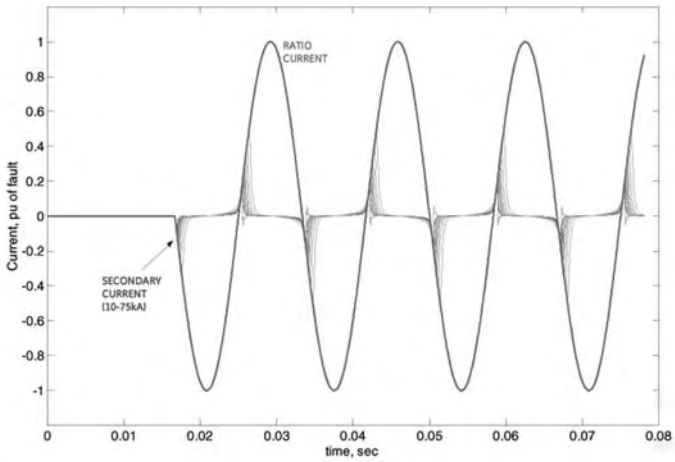

Fig.5a. 50:5, C10, CT with a burden of 0.2ohms under fault current up to75kA (symmetrical).

Figures 5a through 6b present a series of secondary currents superimposed on the ratio current. The primary current ranges from 200 to 1500 times the CT rating (10kA to 75kA in this case). All traces are rescaled to the peak of the ratio current for easy visualization (in this way all currents have the same graphical scale). Figure 5 is for symmetrical currents, and Figure 6 for the fully offset currents.

These figures illustrate severity of the problem. The secondary current is as low as 5-8% of the expected ratio current, and exhibits spikes shorter than 1ms when the fault current is as high as 75kA. Please note that this 50:5, C10, CT has a burden of 0.2ohms, virtually making it into an IEEE C57.13 “C5 relay class” equivalent.

It is important to observe that the secondary current, despite being extremely low compared with the fault current, is still very large compared with the CT and relay ratings:

For example, consider a fully offset 75kA current and a 50:5, C10, CT of Figure 6b. The peak value of the secondary current is only about 5% of the peak value of the fault current, but this translates to 0.05*75kA* 2 / (50:5) = 530A peak secondary, or 530A peak/(2 *5A) = 75 times rated value of the relay. This is a substantial current considering a typical conversion range of a microprocessor-based relay is 20-50 times the rated current. Figure 7 shows the relation between the peak

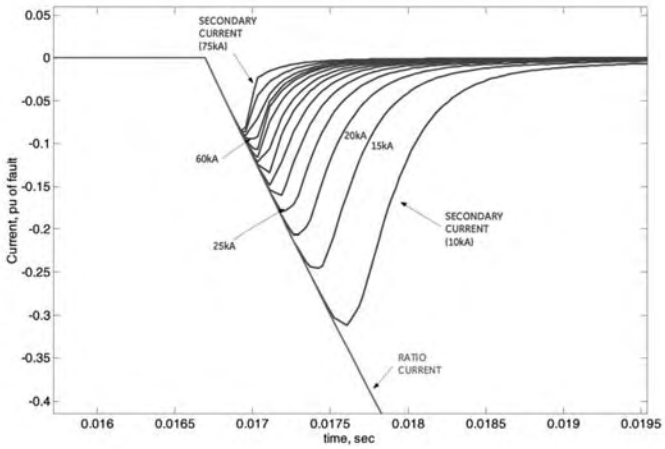

Fig.5b. 50:5, C10, CT with a burden of 0.2ohms under fault current up to75kA (symmetrical). First half-cycle of the secondary current.

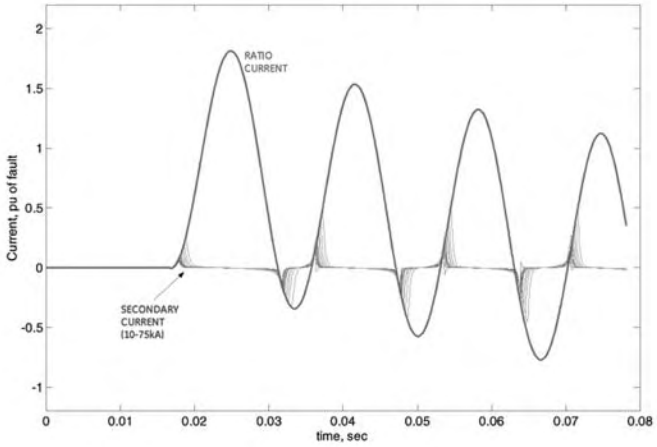

Fig.6a. 50:5, C10, CT with a burden of 0.2ohms under fault current up to75kA (fully offset).

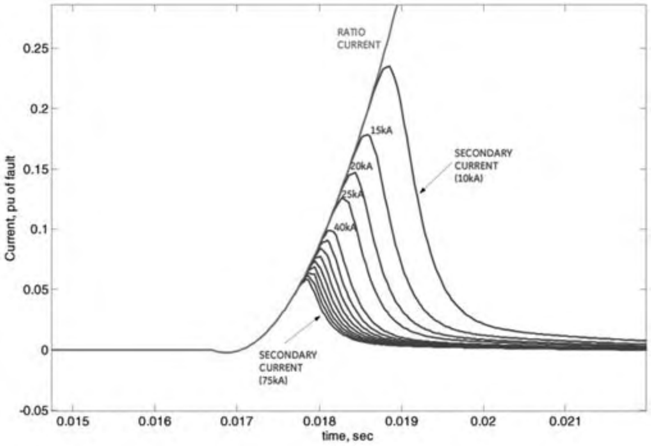

Fig.6b. 50:5, C10, CT with a burden of 0.2ohms under fault current up to75kA (fully offset). First half-cycle of the secondary current.

value of the secondary current, and peak value of the ratio current for the simulated CT (10kA-75kA range).

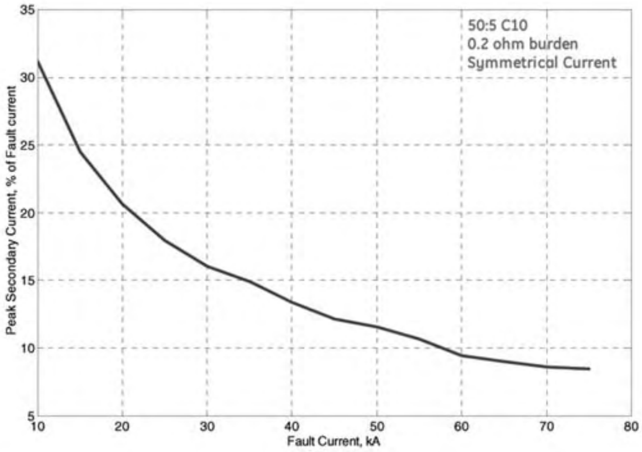

Fig.7a. 50:5, C10, CT with a burden of 0.2ohms: relation between the peak secondary current and peak fault current (symmetrical waveform).

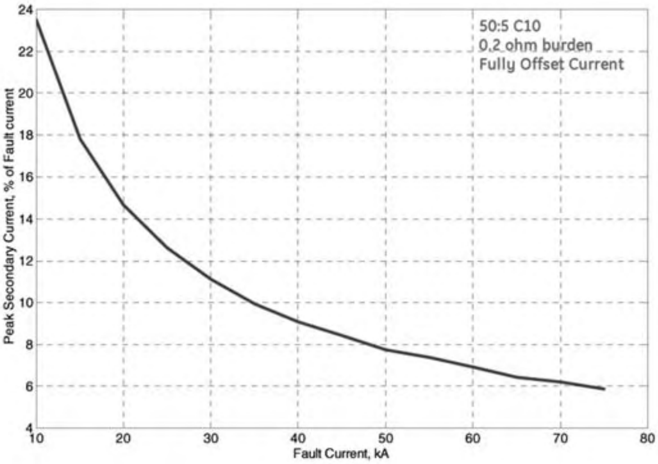

Fig.7b. 50:5, C10, CT with a burden of 0.2ohms: relation between the peak secondary current and peak fault current (fully offset waveform).

Consider however, that it is the short duration of the peaks of the secondary current, not the low magnitude of those peaks that is important from the point of view of the signal strength delivered to the relay.

3. MICROPROCESSOR-BASED RELAYS AND SATURATED CURRENT WAVEFORMS

As explained and illustrated in the previous section, low-ratio CTs pass proportionally less and less signal energy to the relay when the primary current increases dramatically. In an extreme case of the fault current being 1000 times the CT rating, only a small percent of this current, in the form of short spikes, would be delivered to the relay. This section explains and illustrates how a typical microprocessor-based relay responds to such waveforms.

Response of Instantaneous Overcurrent functions is of primary interest.

With reference to Figure 8 a typical relay incorporates input current transformers (galvanic isolation), analog filters (anti-aliasing), A/D converter, magnitude estimator possibly with digital pre-filtering, and an Instantaneous Over-Current (IOC) comparator.

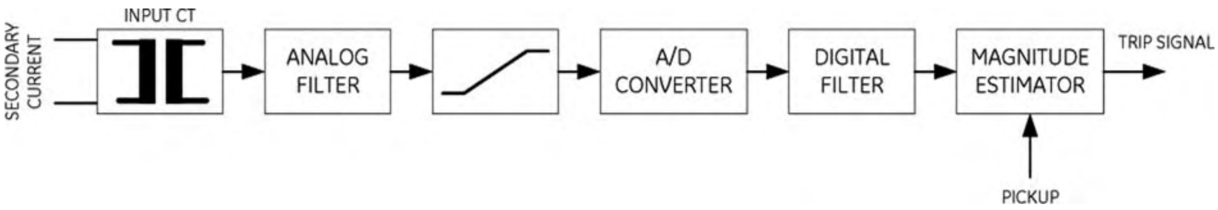

Fig.8. Signal processing chain of a typical relay.

3.1. IMPACT OF RELAY CURRENT TRANSFORMERS

In general, the relay input CTs may saturate, adding to the complexity of the analysis, and to the scale of the problem. However, saturation of relay input CTs may be neglected for the following reasons:

The secondary current is substantially reduced under severe saturation of main CTs.

Moreover, saturation of the main CT makes the secondary current symmetrical, eliminating the danger of exposing the relay input CT to decaying DC components. And thirdly, the secondary current has a form of short lasting spikes. This limits the flux in the cores of the relay inputs CTs.

For example, consider the case of Figure 5. Under, say 75kA of symmetrical fault current, the secondary current is approximately a series of triangular peaks of about 0.08*75kA* 2 / (50:5) = 848A secondary, lasting approximately 0.5-1ms. Assuming 1ms duration of these spikes, the true RMS of this secondary signal is only 120A, or 24 times the 5A rated of the relay input.

In reality, the relay input CT would have some impact on the response of the relay.

Frequency response, i.e. ability to reproduce the short lasting input signal, may play a role.

The theoretical analysis of this paper neglects the impact of relay input CTs. It is believed to be small. This is confirmed through testing of actual relay hardware.

3.2. IMPACT OF THE ANALOG FILTER

Analog filters are implemented in order to prevent aliasing of higher frequencies on the fundamental frequency signal. Typically, a second order filter is used with a cut-off frequency of about 1/3rd of the sampling rate.

Analog filters have a positive impact on the response of the relay to heavily saturated current waveforms. Due to its intended low-pass filtering response, the analog filter reduces the peak values of its input signal and lengthens the duration of such spikes. In a way, the analog filter smoothes out the waveform by shaving its peaks and moving the associated signal energy into the area of lower magnitude. This phenomenon is illustrated in Figure 9.

Given the fact that the peak magnitude of spikes is well above the conversion level of the relay and, as such, it is not used by the relay when deriving the operating quantity, the operation of shifting some signal energy from the peaks into the low magnitude area would increase the operating signal and improve the overall response of the relay.

Figure 9 assumes a linear analog filter, i.e. a filter that would not saturate despite the high magnitude of its input. Most filters, however, are designed using active components (operational amplifiers) and will saturate on waveforms such as the one of Figure 9. Figure 10 shows response of a simplified model of such filter (clamping of the input signal to a linear filter). As seen in the figure, the signal is reduced even more. What is important is that the analog filter shifts some portion of the signal energy into the low magnitude region when it is measured and utilized by the relay.

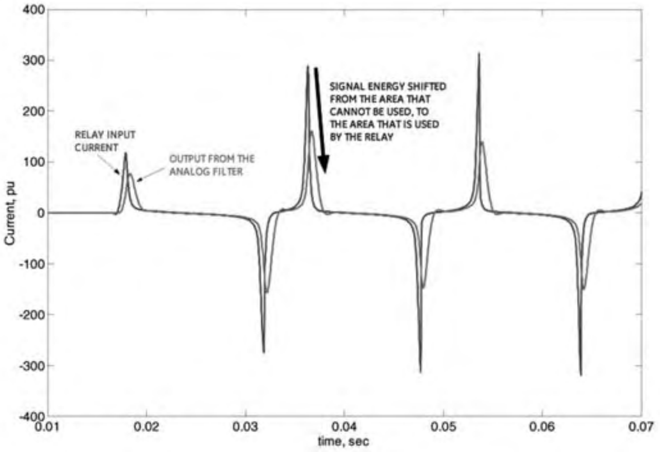

Fig.9. Impact of a linear analog filter on the saturated current waveform (64kA fault current; C10, 50:5, CT with 0.2ohm burden).

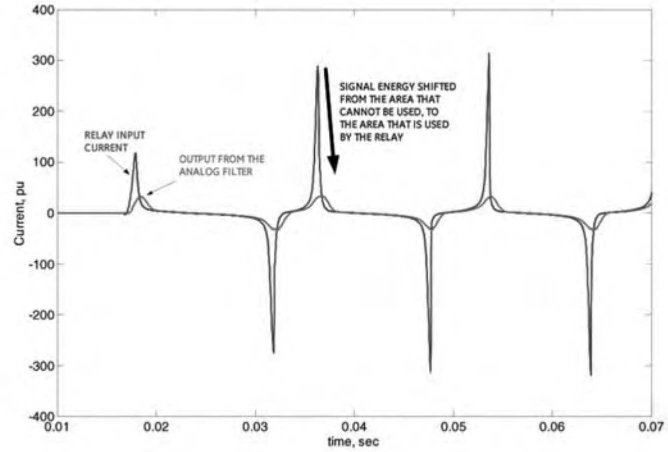

Fig.10. Impact of a linear analog filter on the saturated current waveform (a simplified model of a non-linear filter).

3.3. IMPACT OF THE A/D CONVERTER

The impact of the A/D converter is twofold. First, any converter has a limited conversion range where signals above a certain level are clamped. This is similar to the response of the

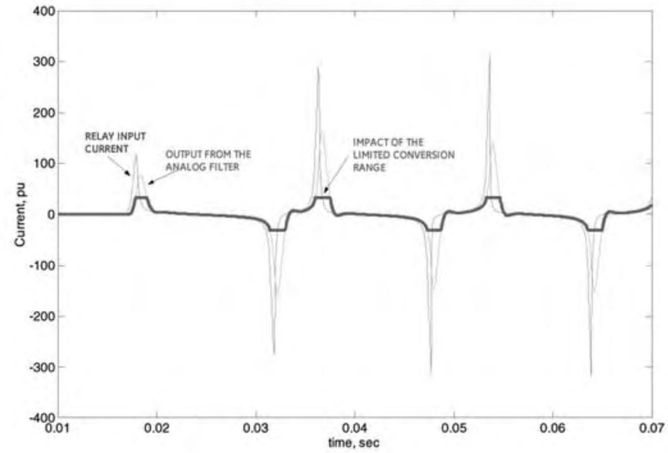

Fig.11. Impact of the A/D converter – clamping (case of Fig.9).

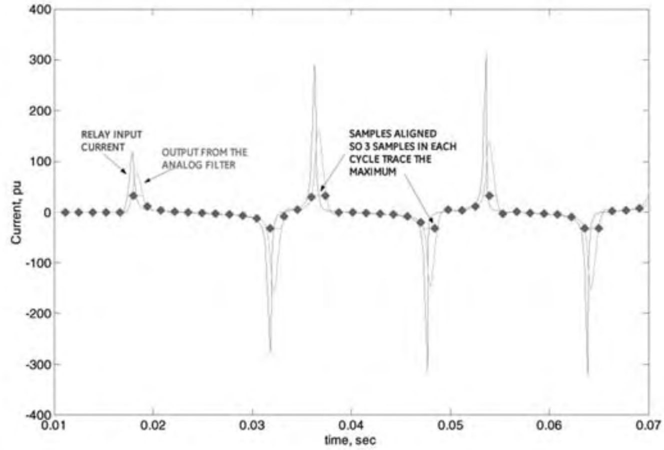

Fig.12. Impact of the A/D converter – sampling (case of Fig.9).

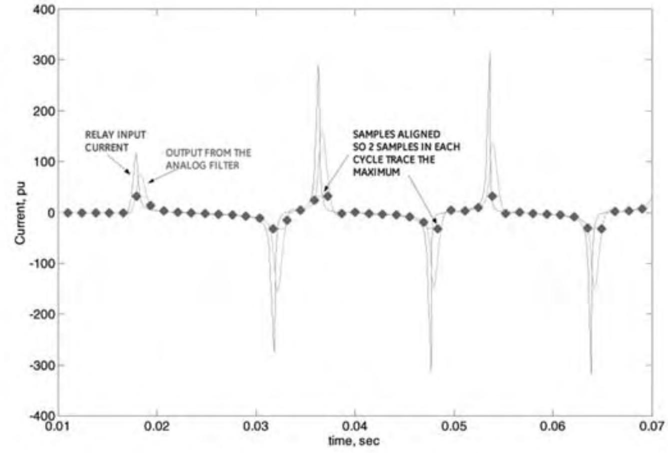

Fig.13. Impact of the A/D converter – samples aligned differently compared with Fig.12.

analog filter in front of the A/D converter (saturation of the amplifiers). The conversion range of today's relays is typically in the 10-50 span. For example, the GE 469 Motor Management Relay clamps the inputs at 28.3* 2 *5A = 200A secondary peak, assuming the 5A rated current.

Figure 11 illustrates the impact of the A/D clamping on the signal processed by a given relay. The second aspect related to the A/D conversion is a limited sampling rate. Today's relays sample at rates varying from 8 to 128 samples per cycle. Industrial relays tend to sample at 8-16 times per cycle.

Given the short duration of the signal pulses produced by a heavily saturated CT, location of A/D samples on the waveform plays an important role. Consider Figures 12 and 13. In Figure 12 the samples lined up in a way that 3 samples in each cycle "caught" the peaks of the signal. In Figure 13 the samples lined up in a way that only 2 samples in each cycle aligned with the peaks. This will result in different values of the operating signal for the IOC function. In the analysis, the worst-case must be considered and, in this context, Figure 13 presents the worse condition.

It is also intuitively obvious that higher sampling rates give better chance to "integrate" the short lasting signal pulses and yield a higher operating signal, and thus better relay performance. This is illustrated in Figure 14 where the sampling is increased from 12 to 16 samples per cycle (s/c).

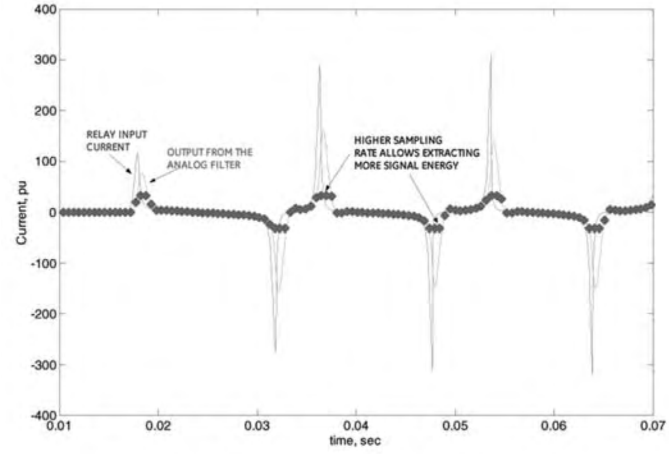

Fig.14. Impact of the A/D converter – higher sampling rate (case of Fig.9).

3.4. IMPACT OF THE MAGNITUDE ESTIMATOR

Microprocessor-based relays calculate their operating signals, such as the current magnitude for the IOC function, from raw signal samples. This process of estimation can include digital filtering for removal of the DC offset that otherwise would result in an overshoot. Typically a Fourier-type or RMS-type estimators are used.

The former extracts only the fundamental component from the waveforms (60Hz) through a process of filtering. This would result in a much lower estimate of the magnitude if the waveforms were heavily distorted.

The latter extracts the total magnitude from the entire signal spectrum yielding a higher response under heavily saturated waveforms. The difference can be tenfold in extreme cases such as the ones considered in this paper.

Figure 15 shows an example of the estimation of a true RMS value. Please note that the relay is subjected to 64kA of fault current, and measures "only" 10-15 pu of current (50-75A secondary, or 500-750A primary). This is only about 1% of the true current, but still 10-15 times relay rated current.

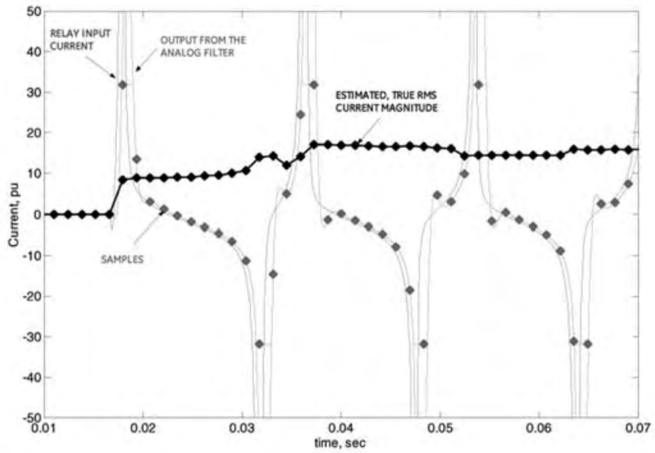

Fig.15. Example of amplitude estimation – true RMS algorithm (case of Fig.9).

3.5. IMPACT OF THE IOC COMPARATOR

The derived operating current signal is compared against a user set threshold. Extra security may be implemented by requiring several consecutive checks to confirm the trip ("security counters"). This impacts when and for what current the relay would operate.

Another aspect is the rate at which the operating conditions are checked. They may be executed with each new sample, every other sample, once a cycle, etc. ("protection pass").

This again impacts if and when a given function operates if the current is not steady. Intimate knowledge of the relay inner workings is required to analyze this, as well as the previously discussed aspects of the relay response.

The next section proposes a methodology for reduction of the many factors impacting response of a given relay to waveforms produced by a given CT in order to facilitate practical analysis and application in the field.

4. METHOD OF QUANTIFYING RESPONSE OF IOC PROTECTION UNDER CT SATURATION

This section presents a methodology for reduction of the many factors impacting response of a given relay to waveforms produced by a given CT in order to facilitate practical analysis and application in the field.

As shown in the previous subsection, any given relay reduces the signal coming from the CT to a series of pulses. These pulses are further limited in magnitude by the conversion range of the relay, while their duration is impacted by the natural inertia of the analog input circuitry of the relay (input transformers, analog filters). As a result considerable variability is removed in the A/D samples in response to the CT parameters. Additionally, a typical relay applies averaging when deriving its operating quantities (such as the true RMS). This reduces variability even further.

The above observation facilitates the following method of quantifying response of any given relay to any given CT. The method starts with a portion to be completed by relay manufacturers as follows:

1. Assume a nominal burden of a given CT. Under different burden, a given CT could be always re-rated by the application engineer based on the known principles.

2. Simulate the CT with and without DC offset in the primary current. Assume a typical X/R ratio for industrial applications (X/R = 15). Repeat for different ratios if required.

3. Vary the AC component in the primary current from the CT rated value up to 64kA.

4. Use a digital model of a given relay, or the actual relay, to find the operating quantity of an IOC function for a given fault current. When simulating, consider the minimum measured value within the timing spec of the IOC function. When testing the actual hardware, look for consistent operation within the timing specification of the relay.

5. Vary the alignment of samples with respect to the waveform in order to get the worst-case scenario. When simulating, explicitly align the samples in different patterns. When testing the actual relay, repeat the test several times to make sure the relay operates consistently.

6. The value found in step 5 is the highest setting that could be used for the IOC function to guarantee operation within the timing specification for a given fault current. This pair of fault current/maximum pickup setting becomes a point on the 2D chart.

7. Repeat the above for various fault currents. The obtained points constitute a characteristic for the considered CT and relay.

8. Repeat the above for various CTs obtaining a series of characteristics for the considered relay.

Figure 16 below shows the important signals for a certain relay fed from a 50:5 C10 with 0.2ohm burden under the symmetrical fault current of 1kA (or 20 times rated). Please note that this particular plot is for a burden different than nominal. The Figure shows that the relay would operate for this case within the timing specification as long as the setting is below 8pu. The (20pu,8pu) pair becomes a dot on the chart.

Figure 17 shows the same relay and CT under the current of 10kA (or 200 times rated).

The Figure shows that the relay would operate for this case within the timing specification as long as the setting is below 15pu. The (200pu,15pu) pair becomes a dot on the chart.

Figure 18 shows the same relay and CT under the current of 50kA (or 1000 times rated).

The Figure shows that the relay would operate for this case within the timing specification as long as the setting is below 14pu. The (1000pu,14pu) pair becomes a dot on the chart.

Repeating this for various fault currents, with and with-

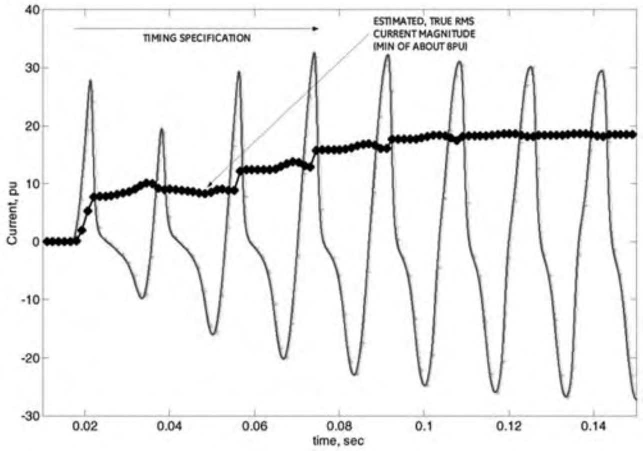

Fig.16. 50:5, C10 CT feeding a relay. Fault current of 1kA (20 times rated).

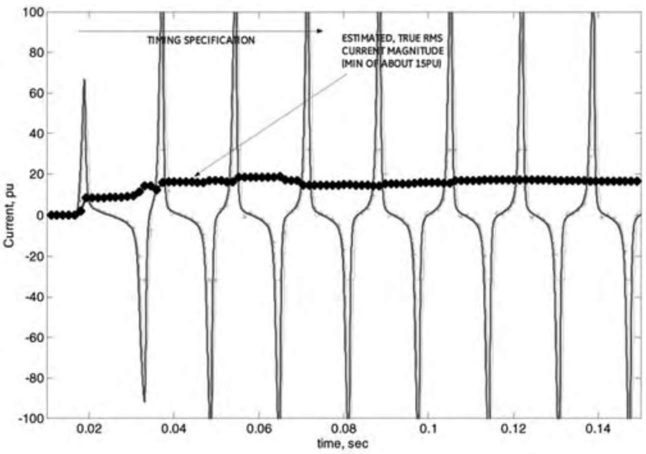

Fig.17. 50:5, C10 CT feeding a relay. Fault current of 10kA (200 times rated).

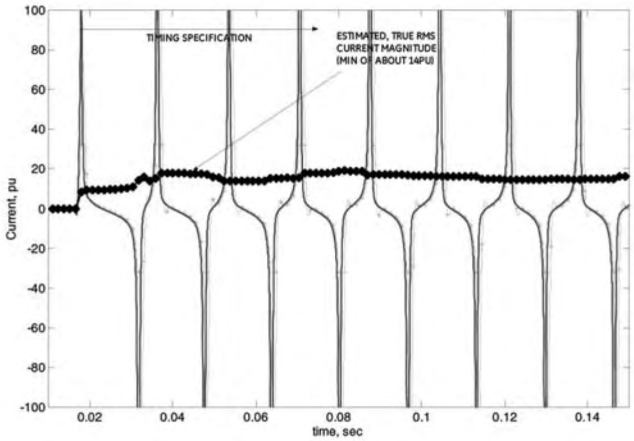

Fig.18. 50:5, C10 CT feeding a relay. Fault current of 50kA (1000 times rated).

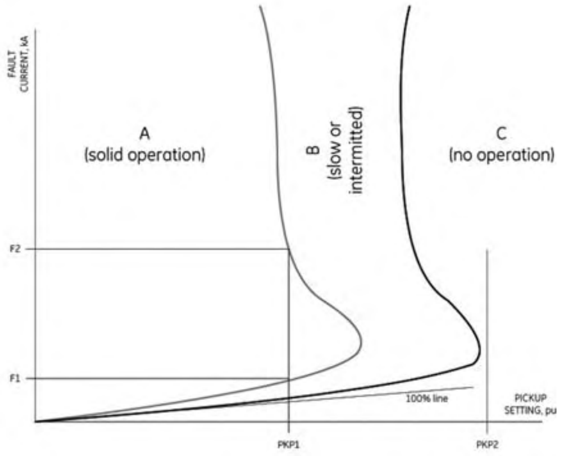

Fig.19. The concept of "fault current – IOC pickup" curves.

out DC offset, while varying the alignment between samples and waveforms, and plotting these as dots on the chart would divide the fault current/pickup plane into three regions: solid operation (A), intermittent or slow operation (B), and no operation (C) as depicted in Figure 19.

The fault current – IOC pickup curves are interpreted as follows: if the CT were perfectly linear, and the relay had an infinite conversion range, the relay would see exactly 100% of the actual primary current, and would operate if the fault current equals the entered IOC setting. This would constitute a straight line as shown in Figure 19. Due to CT saturation and the finite relay range, the relay sees less than the actual (ratio current), and thus needs more current than 100% of the setting in order to operate. Therefore, the curves climb up away from the 100% line.

If set to PKP1, the relay would operate as long as the fault current is above F1 value (crossing the pickup line), and the fault current is below F2 value (severe saturation decreasing the relay operating current below the pickup value).

If set to PKP2, the relay would never operate, because the operating value never goes above the PKP2 value: first, the current is too small; next the current is too large causing enough saturation to keep the operating quantity low.

Solid (guaranteed) operation of the IOC functions is of primary interest here. Therefore, the left line dividing solid operation form the intermitted operation shall be provided to the users as shown in Figure 20. Charts for different CTs shall be included on the same graph.

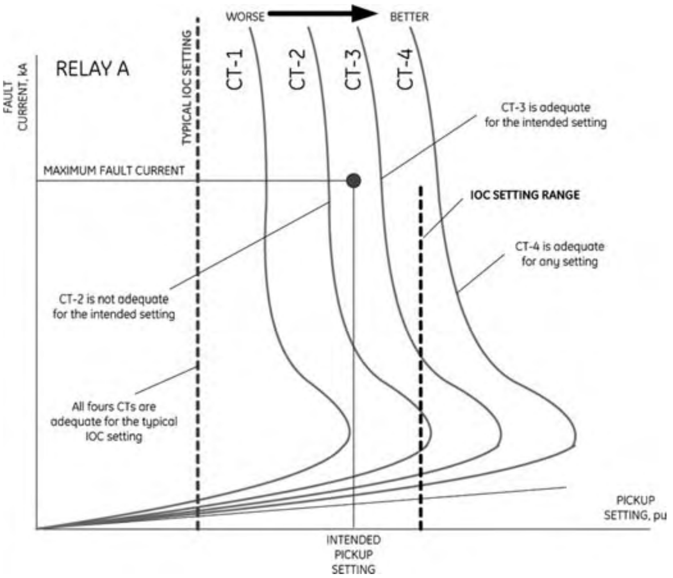
WORSE
BETTER
RELAY A
FAULT CURRENT, kA
TYPICAL IOC SETTING
CT-1
CT-2
CT-3
CT-4
CT-3 is adequate for the intended setting
MAXIMUM FAULT CURRENT
IOC SETTING RANGE
CT-4 is adequate for any setting
CT-2 is not adequate for the intended setting
All fours CTs are adequate for the typical IOC setting
PICKUP SETTING, pu
INTENDED PICKUP SETTING

Fig.20. The concept of fault current – IOC pickup curves: Selecting CT for a specific relay, specific maximum fault level and specific pickup setting.

The user applies the chart as follows.

For an intended pickup level, the user reads the fault current from the curve. If a fault of this magnitude happens, this particular relay fed from this particular CT would see just enough current to operate. This point defines the boundary of safe operation. If the actual maximum fault current is below that value, the application is safe; if above, the relay may trip slow or not at all for currents above the value from the chart.

If the application has a problem, the user could use a better CT. A family of curves shall be provided for various CTs. A CT shall be selected with the characteristic to the right of the intended pickup – maximum fault current point.

Please note that given the maximum fault current in Figure 20, CT-4 is adequate for any setting value (the CT-4 curve is located to the right from the maximum relay setting line). The CT-4 of this example is the lowest class/ratio CT that does not limit at all application of this particular relay. Vast majority of CTs of a given series fall into this category, and the curves are really needed only for the CTs below this borderline case.

Please note that given the typical IOC setting of 12pu or so used for short circuit protection of motors, all four CTs in the example of Figure 20 are adequate (even the CT-1 curve is located to the right from the typical setting line).

To understand better application of the curves, consider a relay and two CTs as in Figure 21. Assume a setting of 19pu is to be used on this particular relay fed from CT-1 on the bus with short circuit capacity of 50kA. Because the 50kA/19pu point is outside the CT-1 curve, this application is not secure. With this setting the relay would operate reliably up to the fault current of 15kA. This CT could be used with settings below 17.5pu.

If the 19pu setting is a must, and the short-circuit capacity is 50kA, CT-2 shall be used. Its curve is to the right of the 50kA/19pu point, meaning the relay would always operate for faults fed from this bus with a setting of 19pu.

Assume the CT-2 is used with this relay: The highest setting one could apply under any practical fault level is 21pu.

As illustrated above, the proposed fault current – pickup chart is a powerful tool to evaluate and adjust applications of IOC protection with low-ratio CTs.

The method can be used not only to match CTs to relays, but vice versa as well. For a given CT, a series of curves can be produced that show the maximum allowable IOC setting for different relays and different fault current levels.

The CTs on the fault current–pickup charts shall be presented assuming nominal burdens. For varying burdens, the CT will get re-rated by an application engineer based on the well-known principles. For applications with long leads, the charts play a role in selecting proper wires in order to meet the required performance.

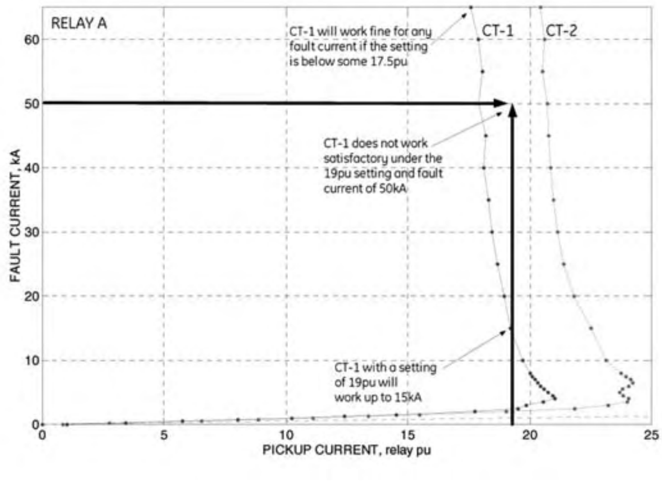

Fig.21. Using the fault current–pickup setting charts.

5. ANALYTICAL ANALYSIS OF SELECTED MULTILIN RELAYS

Several MULTILIN relays have been evaluated based on the approach outlined in the previous section. The evaluation assumes a simplified model of relays giving consideration to their actual analog filters, conversion ranges, sampling rates,

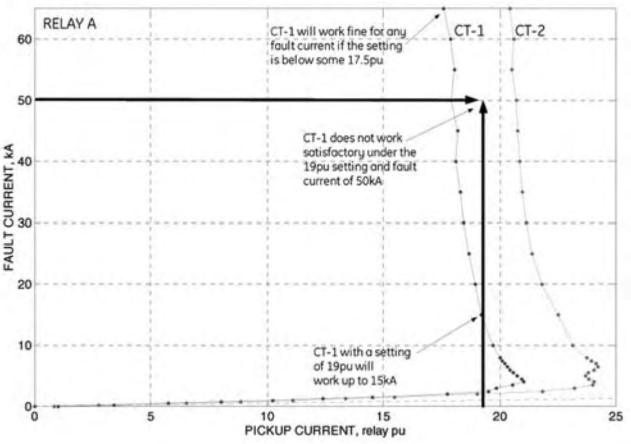

Fig.22. Fault current–pickup charts for the 469 relay (f/w 5.0, h/w rev. I) and two sample CTs (relay setting range for IOC is 20pu). Application in 60Hz systems.

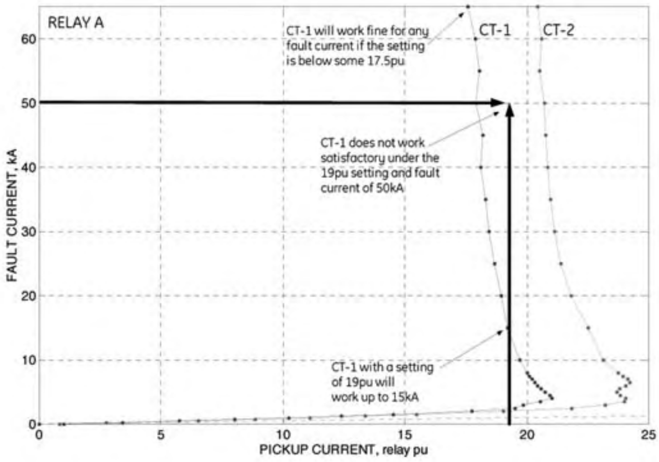

Fig.23. Fault current–pickup . charts for the 489 relay (f/w 1.53, h/w rev. I) and two sample CTs (relay setting range for IOC is 20pu). Application in 60Hz systems.

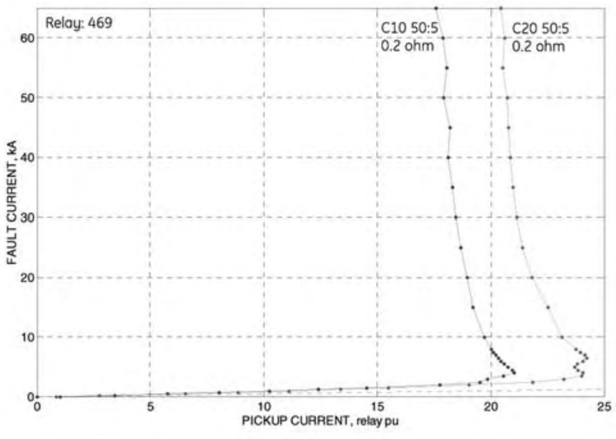

Fig.24. Fault current–pickup charts for the 369 relay and two sample CTs (relay setting range for IOC is 20pu). Application in 60Hz systems.

digital filtering and phasor estimators.

The analysis has been presented for 2 selected CTs (50:5, C10, 0.2ohm burden, and 50:5, C20, 0.2 ohm burden). Note, that these are relatively poor performance CTs. With the burden of 0.2ohms, the first CT is equivalent to a "C5 class".

Figures 22 through 26 present the fault current-pickup charts for the 469, 489, 369, 239 and 750 relays.

It is clear from the figures that using very low-ratio CTs prevents applying the relays with settings above some 80% of the setting range. For example, with the 50:5, C10, 0.2 ohm CT applied in a 64kA switchgear, the 469 can be set as high as 17pu. The typical setting is considerably lower (some 12pu) which makes the application secure.

6. TEST RESULTS FOR SELECTED MULTILIN RELAYS

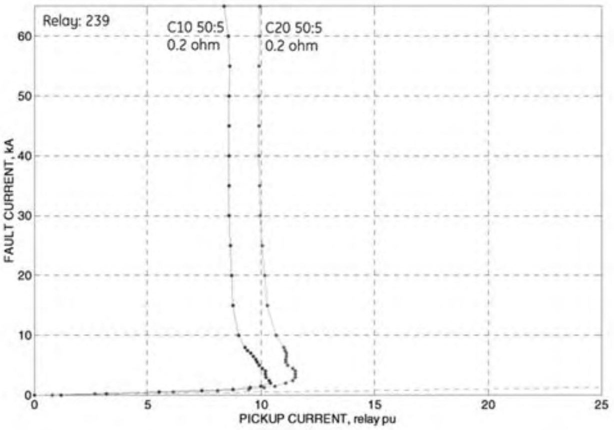

Fig.25. Fault current–pickup charts for the 239 relay and two sample CTs (relay setting range for IOC is 11pu). Application in 60Hz systems.

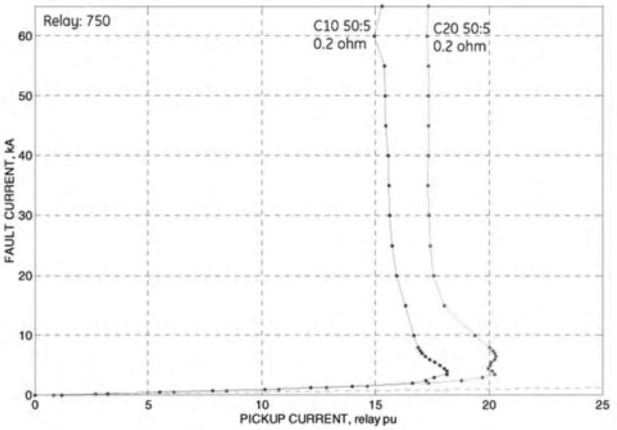

Fig.26. Fault current–pickup setting charts for the 750 relay and two sample CTs (relay setting range for IOC is 20pu). Application in 60Hz systems.

The analysis of section 5 has been validated on the actual relay hardware. Figures 27 and 28 present results (for currents up to 200 times the rated) for the 469 and 369 relays. It could be seen that the theoretical prediction and response of the actual relay match well in the tested region of the chart.

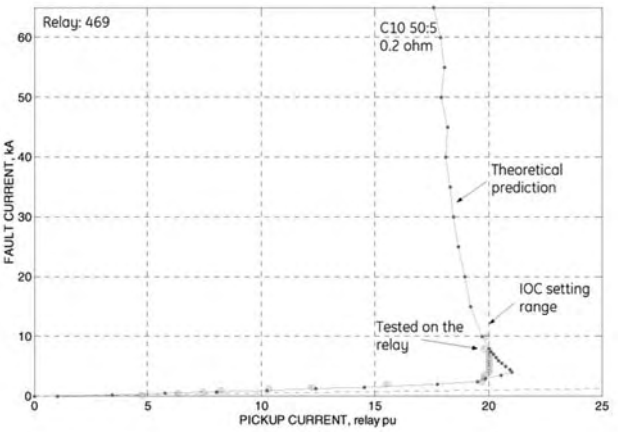

Fig.27. Fault current–pickup charts for the 469 relay (f/w 5.00, h/w rev. I) and a sample ITI CT (theoretical analysis vs relay test results). Application in 60Hz systems.

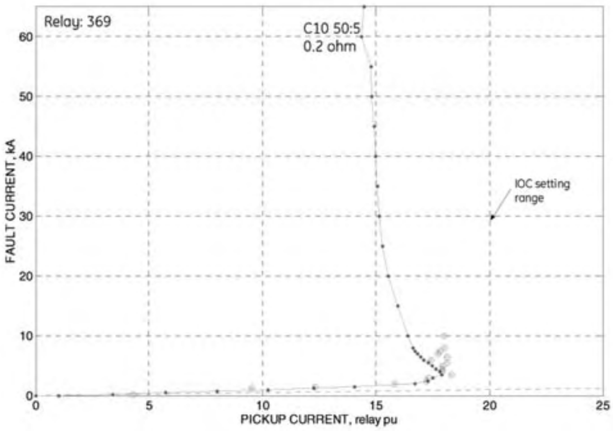

Fig.28. Fault current–pickup charts for the 369 relay and a sample CT (theoretical analysis vs relay test results). Application in 60Hz systems.

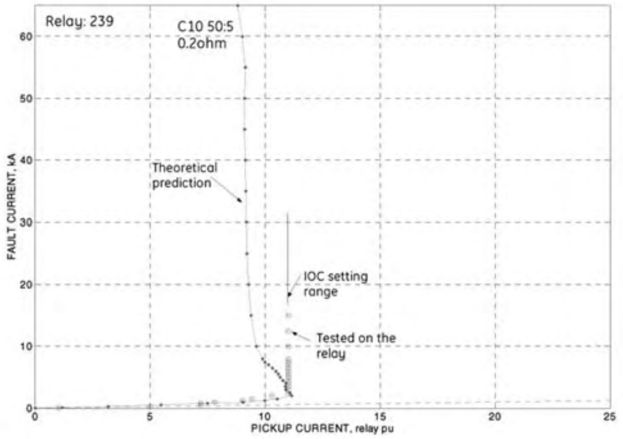

Fig.29. Fault current–pickup charts for the 239 relay and a sample CT (theoretical analysis vs relay test results). Application in 60Hz systems.

The relays have been tested as follows: A given saturated waveform is played back to the relay; an IOC setting is decreased from the maximum available on the relay to the point when the relay starts operating consistently, and all responses are within the published trip time specification. This setting is considered a solid operation point. The fault current – solid operation pickup point is put on the chart, and the process continues with the next fault level.

The relays were tested using playback of waveforms generated from a digital model of the CT. This model was verified as well in order to gain absolute confidence in the accuracy of the presented charts.

7. VALIDATION OF THE CT MODEL

Using an adequate CT model is critical to the accuracy of the analysis. CT modeling techniques are relatively precise when applied in the typical signal ranges, i.e. under currents up to a few tens of the CT rated current. This paper assumes currents in hundreds of the rated value, and therefore calls for cautious approach to CT modeling.

The CT model used in this study is supported by the IEEE Power System Relaying Committee and has been verified by multiple parties. It is justified to assume, however, that the verification was limited to relatively low current levels. The model shall be verified on fault currents as high as 800 rated in order to make sure the unusually high flux densities, and other aspects do not change the nature of the CT response compared with more regular situations. This must be done using actual CTs and high power testing equipment.

This section compares test results of a 50:5 C10 and a 50:5 C5 CT with the waveforms obtained from the digital model, in order to validate the model. The comparison is done for currents being hundreds of the CT rated.

The tests have been done in the high power lab of GE Multilin's Instrument Transformers (ITI) division in Clearwater, Florida. Figures 30 and 31 show a CT under test, and the test setup, respectively. A current source capable of driving 5kA of current is connected to 4 primary turns on the C10 CT. A current source capable of driving approximately 3.6kA of current is connected to 11 turns on the C5 CT. This is equivalent to testing the C10 CT with 20kA of primary current, and the C5 with 40kA of primary current. A 0.2ohm burden resistor is applied to both transformers.

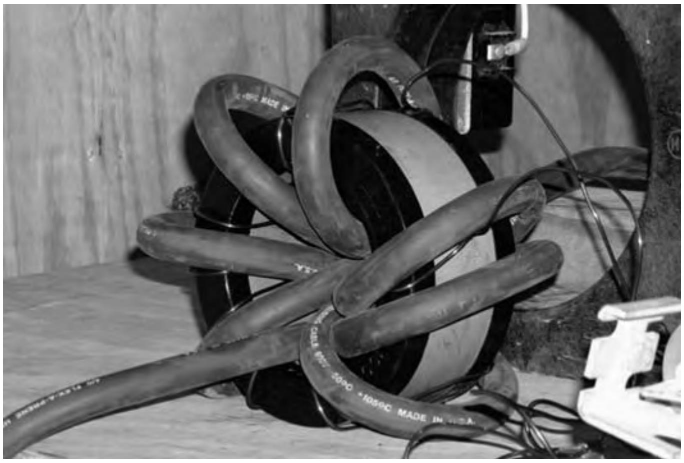

Fig.30. 50:5 C5 CT under test. Multiple primary turns (8 cable loops indicated) used to simulate effectively higher primary current. The reference CT is visible to the right of the CT under test.

A digital scope is used to record traces of the ratio and secondary currents. A 0.3B1.8,

C100, 4000:5 CT is used as a reference CT measuring the primary current.

The tested CTs are demagnetized before each test in order to facilitate the simulation by making the residual flux known (zero).

Fig.31. Test setup.

Figure 32 presents the actual (measured) magnetizing characteristics for the two CTs under test.

Figure 33 shows the primary currents: measured and simulated for a sample 20kA test of the C10 CT.

The current source used in the test cannot be controlled as to the DC offset. Therefore, the primary waveform in the digital simulation has been matched post-mortem to reflect the test waveform.

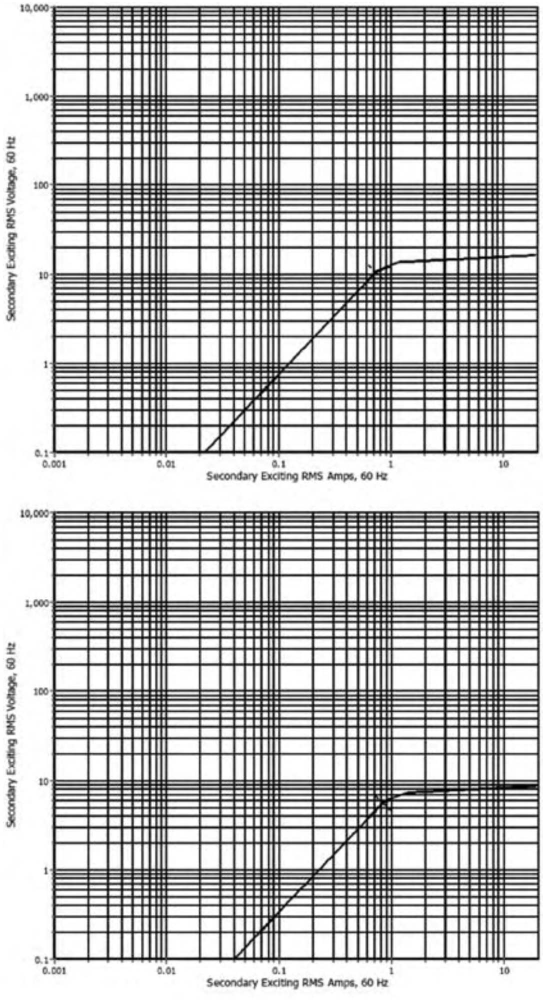

Fig.32. Magnetizing characteristics of the C10 (top) and C5 (bottom) CTs used in the tests.

Subsequently, such primary waveform has been used to exercise the digital model of the CT producing the secondary waveform depicted in Figure 34. The tested and simulated secondary currents' waveforms are inverted in the figure to better indicate the narrow current pulses that otherwise would overlap closely and be difficult to read.

The primary current of Figure 33 is distorted and does not follow a classical exponential DC decay model. This is because of the type of the current source used. The DC constant and distortions are of secondary importance, however, because of the high value of the current.

As seen in Figure 34, the model and actual CT tests match well. The model seems to yield a slightly lower magnitude of the secondary current and, at the same time, slightly narrower pulses of the current. The difference in magnitudes seems to be within 10-15% and is not critical, as this level is several times above the relay cut-off value already. The lower magnitude and width of the pulses, as simulated by the digital model, make the analysis of this report conservative – the actual CT would deliver more energy to the relay compared with the simulated CT.

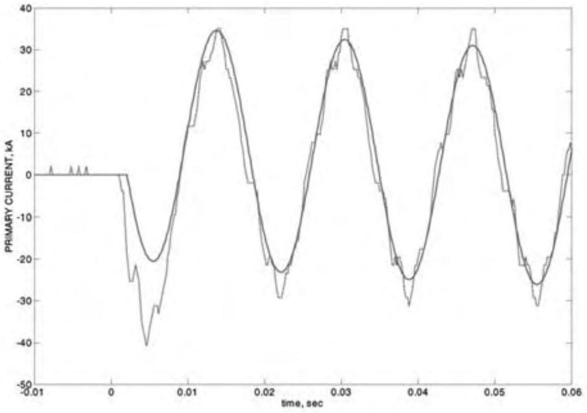

Fig.33. Case 1 – primary currents: test (dotted line) and simulation (solid). A 20kA test of the C10 CT.

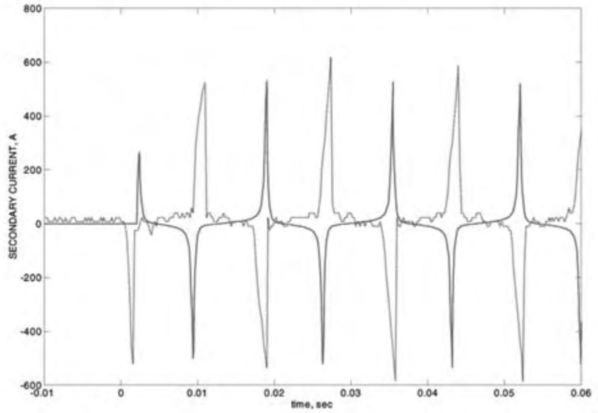

Fig.34. Case 1 – secondary currents: test (dotted) and simulation (solid). The currents are inverted for better visualization. A 20kA test of the C10 CT.

Figure 35 shows a 10kA test of the C10 CT. Again, the model and the test results match well.

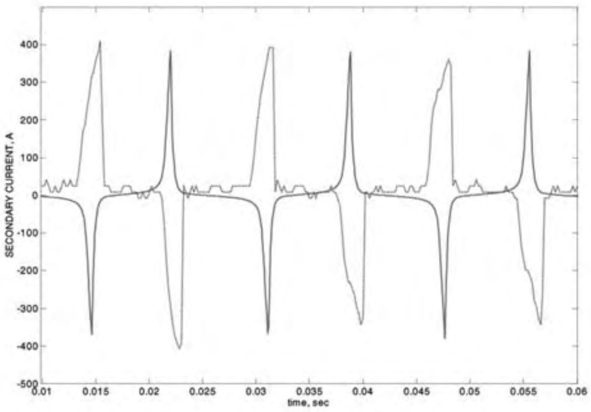

Fig.35. Case 2 – secondary currents: test (dotted) and simulation (solid). The currents are inverted for better visualization. A 10kA test of the C10 CT.

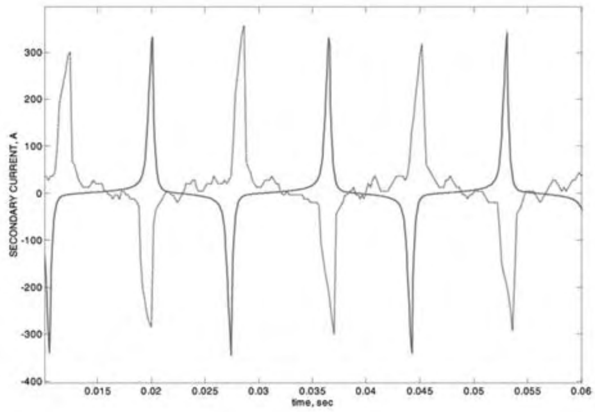

Fig.36. Case 3 – secondary currents: test (dotted) and simulation (solid). The currents are inverted for better visualization. A 32kA test of the C5 CT.

Figure 36 shows a 32kA test of the C5 CT. This approximates a 64kA test of a C10 CT. As seen in the Figure, the CT still delivers current pulses of 300A secondary. Again – the digital model seems to return current pulses of shorter duration, making the analysis of this report conservative.

8. CONCLUSIONS

This document explains issues associated with instantaneous overcurrent protection in industrial applications when feeding protective relays with low-ratio CTs. Extreme cases of CT saturation have been considered to the extent of 64kA of fault current measured by a 50:5, C10 CT.

A methodology has been provided for practical field engineering of CT and relay applications. Simple-to-understand-and-apply charts could be developed as illustrated in this report to quantity a problem and rectify it, if necessary. The proposed methodology eliminates many variables from the analysis, does not require users to apply any sophisticated tools, and is easy to use.

Results of analysis and testing indicate that the combination of low-ratio CTs and very high fault currents could prevent the user from entering very high IOC settings. For a given relay, working with a given CT, in a system with a given maximum short-circuit level, a maximum IOC setting can be found for which the relay will operate within its timing specifications. If a higher setting is required, the relay may respond outside of the spec or restrain itself from tripping. That region of inadequate operation is relatively limited, and occurs only for absolute extreme cases of low-ratio CTs and high fault currents. Moreover, the practical settings are outside of the affected region.

This explains why one does not encounter this problem in the field. On the surface, the problem seems to be very serious – the secondary currents are extremely low compared with the ratio currents. However, these secondary currents are still high enough to activate relays given their practical setting ranges.

The above could be better understood when realizing the source of the problem. A given CT saturates heavily because its ratio is selected to match relatively small load current. If the load current is small, the overcurrent pickup threshold for short circuit protection is small as well (it is a fixed multiple of the load current). The magnitude of extremely high fault currents is a hundreds times, or close to a thousand times the rated current, but this means it is tens or hundreds times the pickup settings. Under such high multiples of pickup, a relay has a large margin between the operating current and the setting. The operating signal will have to be decimated by tens or hundreds times by CT saturation and limited conversion range of the relay, to cause the relay to fail.

It must be emphasized that there is a dramatic difference between relays using Fourierlike approach (cosine and sine filter), and relays based on true RMS value. The latter behave significantly better as illustrated in this report.

This report uses the standard IEEE burden of 0.2 ohms for illustration. The actual burden in typical industrial applications is significantly lower, making sample results of this report conservative. In actuality, the problem is less significant.

Using this methodology, users of GE Multilin's relays can apply them safely and confidently in applications where fault currents exceed rated currents by hundreds of times, even if low-ratio CTs have been used.

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OR
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